Freehold

ROYALTY TRUST

2006 ANNUAL REPORT

TEN YEARS OF ROYALTY INCOME, OF HIGH NETBACKS, OF FINANCIAL STABILITY, OF PROFITABLE RESULTS, OF CONSERVATIVE DEBT MANAGEMENT, OF A CONSISTENT BUSINESS STRATEGY, OF RESPONSIBLE GOVERNANCE, OF A QUALITY INVESTMENT, **OF FREEHOLD ROYALTY TRUST.**

PROFILE

TEN YEARS

FREEHOLD ROYALTY TRUST IS ONE OF THE LARGEST OWNERS OF PRIVATELY-HELD OIL AND GAS ROYALTIES IN CANADA AND THE ONLY ENERGY TRUST IN CANADA WITH THIS KIND OF ASSET BASE. A ROYALTY INTEREST OFFERS THE BENEFIT OF SHARING IN PRODUCTION, WITHOUT THE RESPONSIBILITY FOR NORMAL COSTS ASSOCIATED WITH OIL AND GAS OPERATIONS. OUR HIGH PERCENTAGE OF ROYALTY INCOME RESULTS IN HIGH NETBACKS TO OUR UNITHOLDERS.

Significant Milestones

18.6%
Compound Annual Return

from our $10.00 initial public offering price to our closing price of $14.81 on December 31, 2006, including total cash distributions of $14.30 per Trust Unit (without reinvestment of distributions).

$486 million
Cumulative Distributions

since inception ($14.30 per Trust Unit), representing an average payout ratio of 82% of funds generated from operations.

1996

Inception, November 25

Freehold's $264 million initial public offering in November 1996 provided a unique opportunity to invest in oil and gas royalty assets (mineral title and gross overriding royalty interests).

2001

Acquired Southeast Saskatchewan Properties

In May 2001, we acquired producing and undeveloped mineral title and gross overriding royalty properties for $25.4 million, creating a new royalty area, Southeast Saskatchewan.

2005

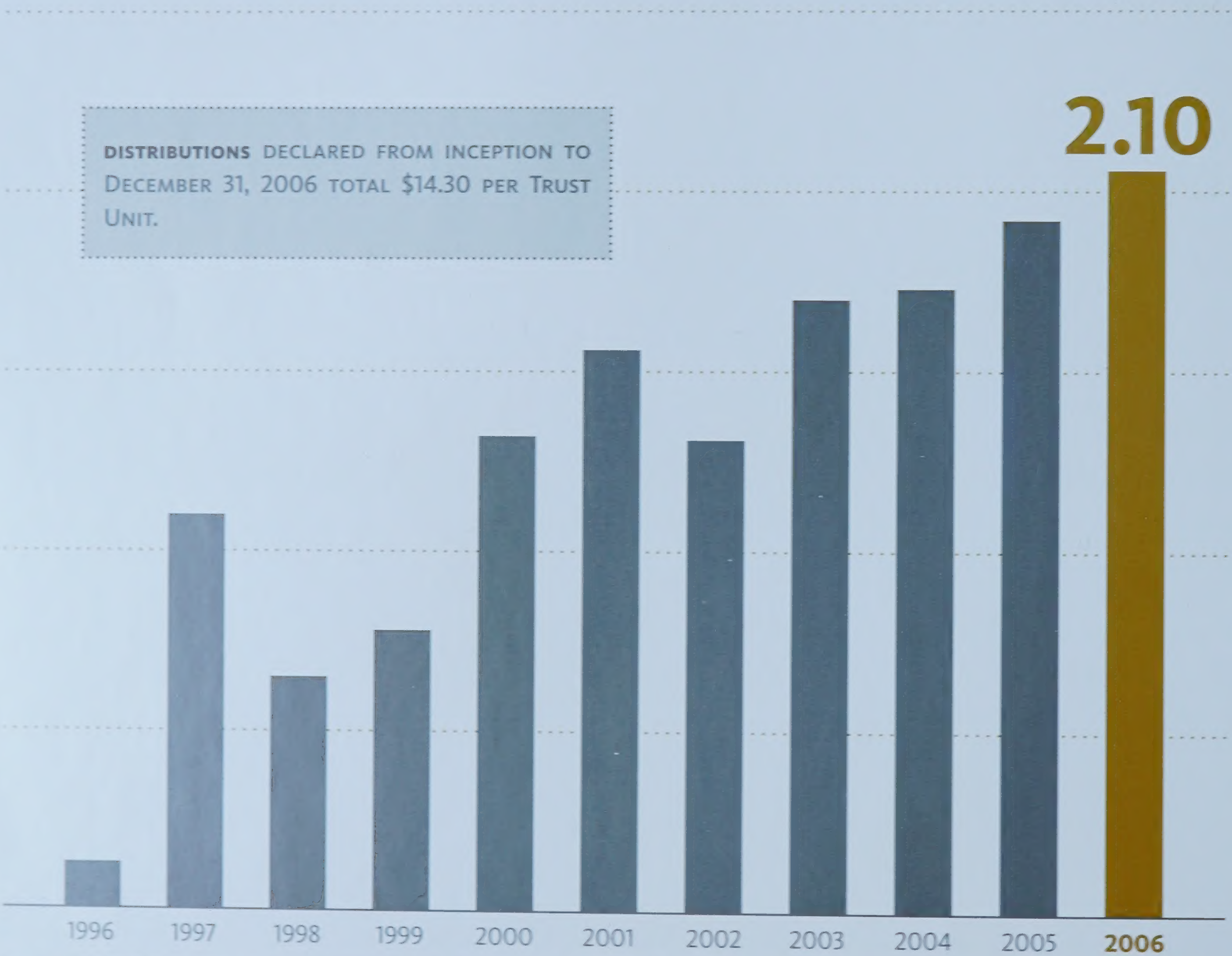
Acquired Petrovera Resources

In May 2005, we acquired Petrovera Resources for $352 million, the largest transaction in our history. The acquisition doubled our royalty land holdings and solidified our position as the only energy trust in Canada focused primarily on royalties.

A Consistent Strategy

Over the past decade, our strategy has remained consistent. We are focused on maximizing distributions, maintaining a conservative approach to debt management, and acquiring additional royalty interests.

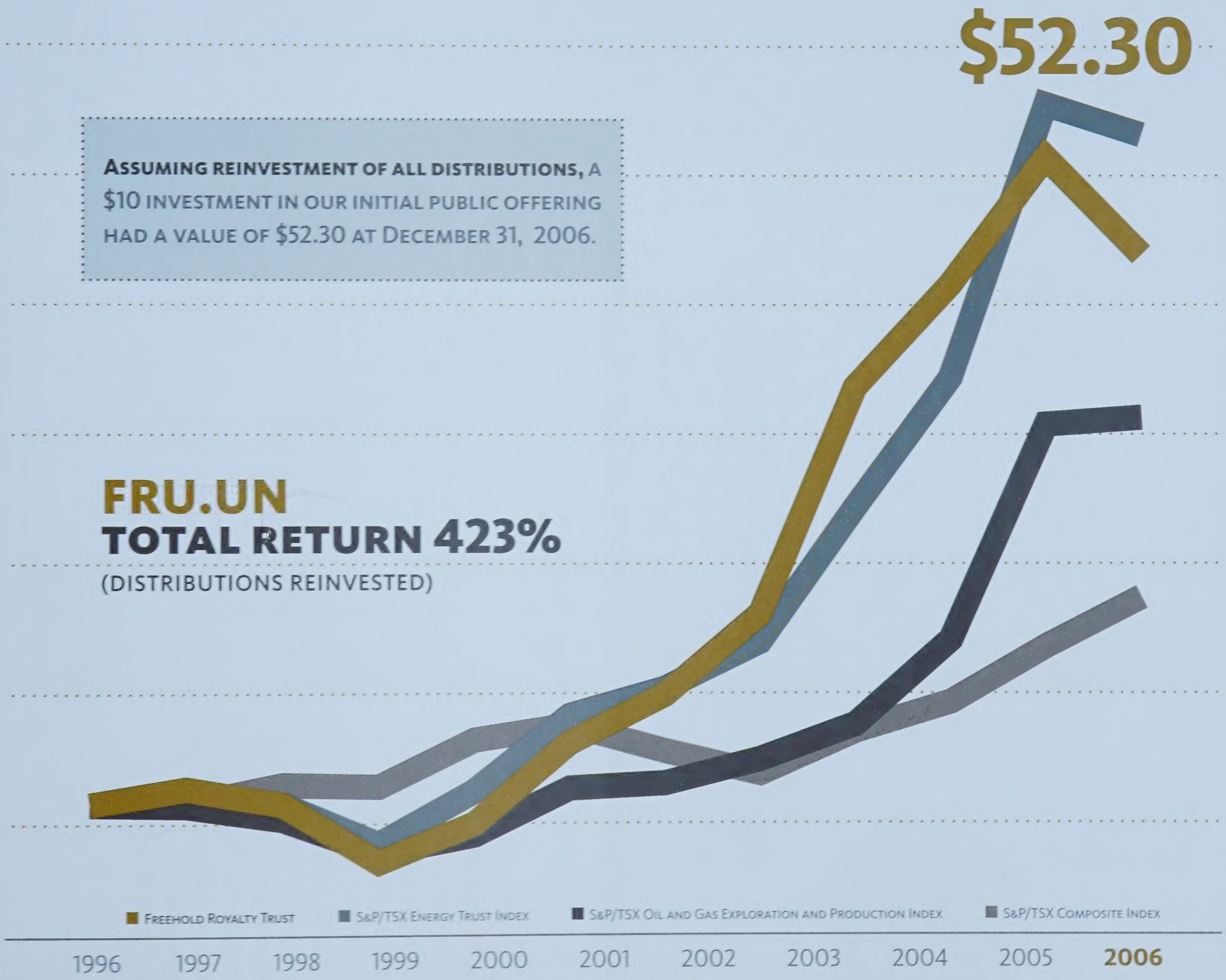
Distributions to Unitholders ($/Trust Unit)



High Payout Ratio

We have maintained a high payout ratio because we don't need large amounts of capital to sustain production. Since inception, we have funded from cash flow 100% of our development expenditures, financed our minor acquisitions, and maintained a very conservative balance sheet by paying down debt – all the while delivering a cumulative payout ratio of 82%.

Cumulative Value of $10 Investment

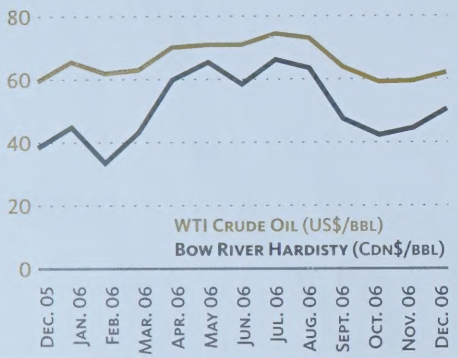


Ten Years as a Trust

As we celebrate our tenth anniversary, the tally of our distributions over the past decade is $486.1 million, or $14.30 per Trust Unit. We have paid out distributions well in excess of our $10 initial public offering price. Unitholders who held our Trust Units from the beginning and reinvested all distributions were rewarded with a total return of 423% to the end of 2006.

2006 Year in Review

Average Benchmark Oil Prices



The benchmark Bow River Hardisty oil price is a close proxy for our average oil price realizations. In March 2006, new pipeline access expanded the market for this type of crude.

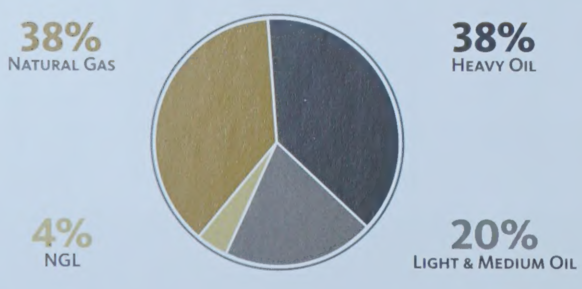
Average AECO Natural Gas Prices

(Cdn$/mcf)

Since the beginning of 2006, natural gas prices have weakened from the record highs of 2005, as gas storage levels remain above the five-year average.

Production Profile

(boe/d)



In 2006, our production was 38% natural gas and 62% liquids. About 60% of our liquids production (38% of our total boe production) was heavy oil.

Distributions Declared

($/Trust Unit)

The weakening in commodity prices in late 2006 prompted our board of directors to reduce the monthly distribution rate to $0.15 per Trust Unit.

2006 Financial Highlights

HIGHLIGHTS

FINANCIAL

($000s, except as noted)	2006	2005	Change
Gross revenue	**143,067**	136,914	4%
Operating income	**130,927**	126,793	3%
Net income	**45,181**	58,346	-23%
Per Trust Unit, basic and diluted *($)* [1]	**0.92**	1.36	-32%
Funds generated from operations	**119,849**	118,034	2%
Per Trust Unit *($)* [1]	**2.44**	2.76	-12%
Distributions declared	**103,100**	84,810	22%
Per Trust Unit *($)* [2]	**2.10**	1.92	9%
Development expenditures	**11,446**	7,982	43%
Long-term debt	**100,000**	107,000	-7%
Unitholders' equity	**344,448**	399,471	-14%
Trust Units outstanding, period end *(000s)*	**49,174**	49,032	–
Weighted average *(000s)*	**49,086**	42,812	15%

OPERATING

Production *(boe/d)* [3]	**8,412**	7,636	10%
Average sales price *($/boe)* [3]	**46.07**	48.53	-5%
Operating netback *($/boe)* [3]	**42.64**	45.49	-6%
Reserves *(Mboe)* [3, 4]	**28,012**	30,530	-8%
Land holdings *(gross acres) (000s)*	**2,069**	2,006	3%
Undeveloped land *(gross acres) (000s)*	**598**	555	8%

1 Based on the weighted average number of Trust Units outstanding during the year.
2 Based on the number of Trust Units issued and outstanding at each record date.
3 To provide a single unit of production for analytical purposes, natural gas production and reserve volumes are mathematically converted to equivalent barrels of oil (boe) at a ratio of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The boe ratio approximates an equivalent energy value, useful for comparative measures, but may not accurately reflect individual product values.
4 Net proved plus probable reserves, evaluated under National Instrument 51-101.

MESSAGE TO UNITHOLDERS

2006 was a milestone year for Freehold as we marked our tenth anniversary. On November 25, 1996, we completed our initial public offering and began trading on the Toronto Stock Exchange.

In our 1996 annual report, I stated: "Through ownership of the Trust Units, you are participating in an attractive investment with uniquely desirable attributes." I am pleased to report that the assets we acquired with the $264 million proceeds of our IPO have performed very well over the past decade. We have enhanced our holdings over the past ten years with acquisitions that have complemented our original asset base, and we remain focused on acquiring additional royalty assets.

Freehold achieved solid financial and operating performance in 2006, despite a softening in commodity prices throughout the year, as our results continue to benefit from the Petrovera acquisition completed in May 2005. Distributions paid or payable to Unitholders reached a record $2.10 per Trust Unit in 2006.

An easing of geopolitical pressures and adequate supplies of crude oil resulted in a softening in world oil prices in the latter half of 2006. Nevertheless, the benchmark WTI crude oil price remained above historical norms, averaging US$66.22 per barrel in 2006. Of particular relevance for Freehold are the markets for heavy oil and prices for the benchmark Bow River Hardisty stream, which is a close proxy for our average oil realizations. In 2006, new pipeline access expanded the market for heavy oil, resulting in improvements in the price differential between light and heavy crude oil.

Natural gas markets within North America continued to be influenced by weather and storage levels and prices exhibited considerable volatility in 2006. A warmer than normal winter allowed natural gas storage levels to build, causing prices to drop sharply during the low-demand period between summer cooling and winter heating requirements.

While the longer-term outlook points to higher prices, ample inventories, a mild winter, and a slowing U.S. economy could further depress prices in the near term. These commodity price fluctuations serve to reinforce that our cash flows, and thus our distributions, are largely dependent on supply and demand factors that are beyond our control. Due to the unpredictable nature of commodity markets, we continue to believe our 'no hedging' policy is the right strategy for Freehold.

> *2006 was a milestone year for Freehold as we marked our tenth anniversary. On November 25, 1996, we completed our initial public offering and began trading on the Toronto Stock Exchange.*

Industry wide, more than 22,000 wells were drilled in western Canada during 2006, about the same as 2005. Drilling on Freehold's lands was down from 2005's record, although 2006 was still our second best year with 851 gross wells drilled on our lands.

Looking ahead to 2007, we anticipate that lower commodity prices will reduce industry drilling activity, although we are encouraged by the higher number of licensed drilling locations on our royalty lands compared to this time last year. The Petroleum Services Association of Canada forecasts a 10% decrease in the number of wells drilled, with the largest reduction in natural gas regions. Drilling has already shifted to more oil-weighted targets as lower natural gas prices have made the economics of shallow gas and coal bed methane activity less attractive for producers.

Nonetheless, industry activity in western Canada, particularly in the oil sands, remains robust and the demand for people and oilfield services is unprecedented. The oil and gas industry continues to experience higher operating, administrative, and finding and development costs, as well as a severe shortage of experienced professionals and skilled trades. One benefit of an industry slowdown might be to ease these inflationary pressures.

ROYALTY FOCUS CONTINUES TO BE OUR DISTINGUISHING FEATURE

Our greatest asset continues to be the value of our royalty lands. We have royalty interests in 1.9 million gross acres of land throughout the Western Canadian Sedimentary Basin and receive royalties from more than 200 operators. This diversity lowers our risk, while we benefit from their drilling activity.

As a royalty interest owner, we do not pay any of the capital costs to drill and equip the wells for production. Other industry operators pay those up-front costs and then pay a royalty to us on the resulting production revenue – before operating expenses. In addition, we do not incur costs for maintenance and reclamation of wells drilled on our royalty lands. Since 1996, over 5,500 new wells have been drilled on our royalty lands, at no cost to Freehold. In other words, other operators have financed 100% of the development activity on our royalty lands. We are experiencing continued drilling activity on our royalty lands, which helps offset the depletion of our production and reserves.

Our focus on oil and gas royalties has meant that we have not required high levels of capital investment to sustain our asset base and generate production. Our sustaining capital expenditures (related to our working interest properties) have amounted to about 8% of annual funds generated from operations. Since inception, we have funded 100% of our development expenditures, financed our minor acquisitions, and maintained a very conservative balance sheet by paying down debt. These results were accomplished even though 82% of cash flow was distributed to our Unitholders. To the end of 2006, we have returned $14.30 in cumulative distributions, yielding a total return of 423% (distributions reinvested). Our royalty interests have helped us to deliver this strong performance.

EXECUTING A CONSISTENT STRATEGY

Our primary goal is to extend cash distributions over the long term by actively managing our assets to sustain production and extend reserve life, without diluting our Unitholders. Our strategy to achieve this is to:

- acquire appropriate assets with a bias toward royalty interests;
- pursue development opportunities to optimize reserves and production on our working interest properties;
- maintain an aggressive audit program to ensure that royalties are correctly calculated and paid; and
- maintain a conservative approach to debt management to provide maximum financial flexibility with respect to acquisitions and development capital expenditures, while maintaining stable distributions.

These strategies are supported by an experienced management team who have managed Freehold's original assets for more than two decades.

PROPOSED INCOME TRUST TAX CHANGES

On October 31, 2006, the Minister of Finance surprised the market by announcing the federal government's intention to impose a tax on the cash distributions of income trusts. The market's reaction to the announcement was immediate and the destruction of value has been devastating for many income trust investors. In the energy trust sector, unit prices to year-end had declined, on average, by 23%. Our Trust Units lost nearly one-quarter of their market value. Freehold's total return for the first ten months of 2006 was 10%, but following Minister Flaherty's announcement, that gain was reversed and we ended the year in negative territory, with our total return down 13%.

So what will this new tax mean for Freehold?

Assuming the proposed changes are enacted, the new tax would apply to Freehold starting in the year 2011, reducing the cash available for distribution to Unitholders. However, greater clarity on the new rules is needed and a great deal of analysis is required within the legal and tax communities. In the meantime, we have been given a four-year grace period before the new tax will apply, and the fundamentals of our business remain strong. We have quality assets and ongoing development on our royalty properties helps to sustain production. Our balance sheet is in good shape, and we are under no pressure to raise capital.

DISTRIBUTION OUTLOOK

Our estimate of cash distributions for 2007 is $1.80 per Trust Unit, giving us an expected payout ratio of about 89%. At the Board's discretion, any excess income available for distribution will be directed toward repayment of long-term debt and improvements in working capital. We expect that this policy will continue in order to allow us to reduce our long-term debt.

ACKNOWLEDGEMENTS

Administering royalty interests takes a special kind of expertise. For this, in addition to geologists and engineers, we need experienced land, accounting, and audit staff. I would like to acknowledge the efforts of the employees of Rife Resources Ltd., who have managed our assets since inception. Rife, which is owned by the CN Pension Trust Funds, reaches a milestone of its own this year, celebrating 25 years in operation.

Each of our directors brings significant oil and gas, financial, and business expertise to Freehold. I would like to thank them for their continued guidance and support, and for the significant time they dedicate to Freehold.

Finally, I would like to thank you, our Unitholders, for your continued confidence in us. While the proposed tax changes have created uncertainty in the trust sector, the quality of our assets remains the same. We look forward to continuing to provide you with solid investment returns for many years to come.

D J Sandmeyer

DAVID J. SANDMEYER
President and Chief Executive Officer
March 14, 2007

Asset Review

Freehold Royalty Trust is one of the largest owners of privately-held oil and gas royalties in Canada and the only energy trust with this kind of asset base. Our focus on royalties represents a conservative departure from owning traditional oil and gas assets. A royalty interest offers the benefit of sharing in production revenue without the operational risks and responsibilities typically associated with oil and gas operations. We receive production revenue from over 23,000 oil and gas wells, and about 80% of our production comes from royalty interests. This diversified asset base and high percentage of royalty income reduces risk while generating superior netbacks.

Our royalty lands are comprised of a large and widely diversified portfolio of properties extending from northeast British Columbia to Ontario. The majority of our royalty income is derived from production in the central area of southern Alberta and southern Saskatchewan.

Freehold also owns working interests in 90 properties located on 203,952 gross (23,264 net) acres of land. Approximately 20% of our production comes from these working interest properties, and half of our working interest production comes from four properties located in Alberta – Hayter, Pembina Cardium Unit No. 9, Ribstone, and Pouce Coupe South Boundary "B" Unit #2.

A royalty interest offers the benefit of sharing in production revenue without the operational risks and responsibilities typically associated with oil and gas operations.

2006 PROPERTIES SUMMARY

	Royalty Interest Properties	Working Interest Properties	**Total Trust**
Land holdings			
Gross acres *(000s)*	1,865	204	**2,069**
Gross undeveloped acres *(000s)*	549	49	**598**
Oil and gas reserves *(net)*			
Proved *(Mboe)*	13,839	4,883	**18,722**
Proved plus probable *(Mboe)*	21,448	6,564	**28,012**
Average daily production			
Oil and NGL *(bbls/d)*	3,753	1,470	**5,223**
Natural gas *(Mcf/d)*	16,660	2,478	**19,138**
Oil equivalent *(boe/d)*	6,530	1,882	**8,412**
Potash *(tonnes/d)*	10.5	–	**10.5**
Development expenditures *($000s)*	–	11,446	**11,446**
Gross revenue *($000s)* [1]	109,189	33,878	**143,067**
Royalty expenses *($/boe)*	–	5.58	**1.25**
Operating expenses *($/boe)*	–	12.09	**2.71**
Operating netback *($/boe)*	45.81	31.64	**42.64**

1 Includes potash revenue, sulphur revenue and other.

2006 NET ASSET VALUE [1]

		Discounted at		
($000s, except as noted)	0%	5%	**10%**	15%
Present value of oil and gas reserves [2]	1,388,973	855,270	**636,267**	517,185
Present value of potash reserves [3]	43,665	18,347	**10,530**	7,360
Undeveloped land [4]	19,412	19,412	**19,412**	19,412
Reclamation fund	2,117	2,117	**2,117**	2,117
Working capital	9,050	9,050	**9,050**	9,050
Bank debt	(100,000)	(100,000)	**(100,000)**	(100,000)
Net asset value	1,363,217	804,196	**577,376**	455,124
Trust Units outstanding	49,174,197	49,174,197	**49,174,197**	49,174,197
Net asset value per Trust Unit	27.72	16.35	**11.74**	9.26

1 Columns may not add due to rounding.
2 Evaluated by Trimble Engineering Associates Ltd. effective December 31, 2006.
3 Potash reserves, evaluated by Rife Resources Ltd., are not subject to National Instrument 51-101.
4 Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2006.

Board of Directors

INDEPENDENT DIRECTORS

WILLIAM W. SIEBENS

Bill Siebens is President and CEO of Candor Investments Ltd. (Calgary), a private energy and investment corporation. He currently serves as a director of the Fraser Institute. He brings special expertise to Freehold with his knowledge of the royalty lands as a portion of these lands were previously owned by Siebens Oil & Gas Ltd. *Mr. Siebens is Chair of the Board and a member of the governance committee.*

D. NOLAN BLADES

Nolan Blades is President of Sunny Gables Holdings Ltd. (Calgary) and a Professional Engineer with extensive experience in the oil and gas industry. Mr. Blades has obtained significant financial experience and exposure to accounting and financial issues as President and CEO of Pursuit Resources Corp. (1993 to 2000) and as a director of a number of companies. He is currently Chairman of Real Resources Inc., and a director of Gemini Corporation and Canoro Resources Ltd. *Mr. Blades chairs the audit and reserves committees and is a member of the compensation and governance committees.*

HARRY S. CAMPBELL, Q.C.

Harry Campbell is Managing Partner of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974 and has extensive experience with Canadian oil and gas transactions and international petroleum and natural gas matters. Mr. Campbell is currently a Director of Delphi Energy Corp., Immersive Media Corp. and The Cathay Investment Fund Limited. *Mr. Campbell is a member of the compensation and reserves committees.*

PETER T. HARRISON

Peter Harrison is Senior Vice-President of Montrusco Bolton Investments Inc. (Montreal) and previously managed Canadian Equities for the CN Investment Division. Mr. Harrison has significant financial experience making investments which involve extensive analysis of financial statements. Mr. Harrison holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario and is a Chartered Financial Analyst. *Mr. Harrison chairs the compensation committee and is a member of the audit and reserves committees.*

DR. P. MICHAEL MAHER

Michael Maher is a Professor and former Dean of the Haskayne School of Business, University of Calgary. He currently serves as a Director of EPI Environmental Technologies Inc. and WellPoint Systems Inc. He has a Bachelor of Science degree in Engineering from the University of Saskatchewan; an MBA from the University of Western Ontario; a Ph.D. from Northwestern University; a Doctor of Commerce (honoris causa) degree from St. Mary's University and is a Professional Engineer. *Dr. Maher chairs the governance committee and is a member of the audit and compensation committees.*

MANAGEMENT APPOINTED DIRECTORS

TULLIO CEDRASCHI

Tullio Cedraschi is President and CEO of the CN Investment Division (Montreal), which manages one of the largest pension funds in Canada. He is currently a Director of the Toronto Stock Exchange and Helix Investments (Canada) Inc. He is Governor Emeritus of McGill University, and Governor of the National Theatre School of Canada. He holds an MBA from McGill University.

DAVID. J. SANDMEYER

David Sandmeyer is President of Rife Resources Ltd. (Calgary). Prior to joining Rife in 1982, he held senior positions with Amoco Canada Petroleum Company Limited. He is a representative on the Canadian Association of Petroleum Producers (CAPP) Fund Advisory Committee of the Alberta Orphan Well Program, President of the Society, Environment and Energy Development Studies (SEEDS), and a former Governor of CAPP. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

Management's Discussion & Analysis

MD&A

The following discussion is management's opinion about our consolidated operating and financial results, which include Freehold Resources Ltd., Freehold Royalty Trust and Petrovera Resources (a general partnership) for the year ended December 31, 2006 and previous periods, and the outlook for Freehold based on information available as at March 14, 2007.

The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the years ended December 31, 2006 and 2005 and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion and analysis should be read in conjunction with the audited financial statements and notes contained in this annual report. Additional information about us, including our annual information form, is available on SEDAR at www.sedar.com.

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). We use the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

NON-GAAP MEASURES

Within this MD&A, references are made to terms commonly used in the oil and gas industry as key performance indicators. We believe that operating income, netback and funds generated from operations are useful supplemental measures to analyze operating performance, leverage and liquidity.

Operating income, which is gross revenue less royalty expense and operating expense, represents the results of operations before general and administrative expense, interest, taxes, depletion, accretion, and management fees.

Operating netback, which is calculated as average unit sales price less royalties and operating expenses; and investor netback, which deducts administrative expense and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis.

Funds generated from operations is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds generated from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit.

Operating income, netback, funds generated from operations, and funds generated from operations per Trust Unit do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at March 14, 2007, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, taxation, regulation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. These forward-looking statements are made as of the date of this MD&A, and we assume no obligation to update or revise them, except as required pursuant to applicable securities laws.

BUSINESS OVERVIEW

Freehold Royalty Trust is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to Unitholders in a tax-effective manner. We receive revenue from oil and gas properties as reserves are produced, which is paid to Unitholders on a regular basis over the economic life of the properties.

At December 31, 2006, our land holdings encompassed approximately 2.1 million gross acres including 598,235 gross acres of undeveloped land. We are one of the largest owners of royalty lands in western Canada. We have gross overriding royalty interests in approximately 1,314,800 acres (including royalty assumption lands), and our mineral title lands cover about 550,600 gross acres. In addition, we hold working interests in 203,952 gross (23,264 net) acres.

Our properties are geographically widespread throughout western Canada. We have interests in more than 23,000 wells and we receive royalty income from more than 200 industry operators. Royalty rates vary from less than 1% (for some gross overriding royalties) to 22.5% (for lessor royalties). This diversity lowers our risk.

Our primary goal is to extend cash distributions over the long term by actively managing our assets to sustain production and extend reserve life without diluting our Unitholders. Our strategy to achieve this is to:

- acquire appropriate assets with a bias toward royalty interests;
- pursue development opportunities on our working interest properties;
- maintain an aggressive audit program; and
- maintain a conservative approach to debt management.

THE MANAGER

The Manager of Freehold is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager is responsible for the day-to-day management of the business of the Trust subject to a supervisory role of the Board. In exercising its powers and discharging its duties under the management agreement, the Manager must exercise the degree of care, diligence and skill that a reasonably prudent advisor and manager in respect of petroleum and natural gas properties in western Canada would exercise in comparable circumstances. The Manager receives a quarterly management fee paid in Trust Units.

The Manager provides certain administrative and support services to the Trust, including those necessary to:

- Ensure compliance with continuous disclosure obligations under applicable securities legislation.
- Provide investor relations services.
- Provide or cause to be provided to Unitholders all information to which Unitholders are entitled under the Trust Indenture.
- Call, hold and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of Unitholders.
- Determine the amounts payable from time to time to Unitholders and to arrange for distributions to Unitholders.
- Determine the timing and terms of future offerings of Trust Units, if any.
- Determine the terms and conditions upon which the Trust may acquire additional royalties.
- Determine the terms and conditions upon which the Trust may from time to time borrow money.

The management agreement has a term of three years and will be automatically renewed on November 26, 2007, unless terminated.

RESULTS OF OPERATIONS

2006 HIGHLIGHTS

- Production averaged 8,412 boe per day, up 10% from 2005.
- Price realizations averaged $46.07 per boe, down 5%.
- Operating netback averaged $42.64 per boe, down 6%.
- Funds generated from operations were $2.44 per Trust Unit, down 12%.
- Distributions to Unitholders totalled $2.10 per Trust Unit, up 9%.
- Net proved plus probable reserves decreased 8% to 28.0 million boe.
- Reserve additions of 1.5 million boe during 2006 replaced 49% of production.
- 851 gross (26.2 net) wells were drilled on our lands during 2006, the second best year in our history.

THE ROYALTY ADVANTAGE

Royalties offer the benefit of sharing in production revenue without exposure to the capital costs, operating costs and environmental costs associated with oil and gas production. Our high percentage of royalty income results in high netbacks, which maximizes distributions to Unitholders.

On May 10, 2005, we acquired Petrovera Resources, a general partnership, for $351.7 million. The purchase price was funded with a combination of equity and debt. The acquisition was accounted for using the purchase method of accounting, with results of operations included from May 10, 2005. The largest transaction in our history, Petrovera added critical mass to enhance stability of our distributions over the long term, from royalty interest assets that were a very good fit with our existing portfolio. The acquisition doubled our royalty production and solidified our position as the only oil and gas trust in Canada focused primarily on royalty interests.

The following analysis illustrates the advantage of our royalty lands from which we receive revenue but do not incur royalty expenses, operating expenses, site restoration expenses, or development expenditures. In 2006, royalty interest properties accounted for 76% of gross revenue and 89% of our distributions.

COMPONENTS OF DISTRIBUTIONS TO UNITHOLDERS

($000s, except as noted)	Royalty Interest Properties	Working Interest Properties	**Total Trust**
Gross revenue	109,189	33,878	**143,067**
Royalty expenses [1]	–	(3,831)	**(3,831)**
Net revenue	109,189	30,047	**139,236**
Operating expenses	–	(8,309)	**(8,309)**
Net operating income	109,189	21,738	**130,927**
General and administrative expenses	(4,389)	(1,192)	**(5,581)**
Interest on long-term debt	(4,638)	(556)	**(5,194)**
Income and capital taxes	–	(291)	**(291)**
Unit-based compensation	225	65	**290**
Expenditures on reclamation	–	(302)	**(302)**
Funds generated from operations	100,387	19,462	**119,849**
Reclamation fund contributions	–	(153)	**(153)**
Development expenditures	–	(11,446)	**(11,446)**
Changes in debt	(14,444)	7,444	**(7,000)**
Acquisitions	–	(5,382)	**(5,382)**
Changes in working capital	5,614	1,618	**7,232**
Distributions declared	91,557	11,543	**103,100**
Percentage contribution	89%	11%	**100%**

1 Net of Alberta Royalty Credit.

HISTORICAL PERFORMANCE REVIEW

Our results are directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates.

SELECTED ANNUAL DATA

($000s, except as noted)	**2006**	2005	2004
Revenue, net of royalty expenses	**139,236**	133,323	75,514
Net income	**45,181**	58,346	36,892
Per Trust Unit, basic and diluted *($)*	**0.92**	1.36	1.17
Total assets	**474,228**	534,078	208,001
Long-term debt	**100,000**	107,000	27,000
Total long-term liabilities	**108,559**	114,968	34,444
Distributions declared	**103,100**	84,810	54,490
Per Trust Unit *($)* [1]	**2.10**	1.92	1.73

1 Based on the number of Trust Units issued and outstanding at each record date.

The acquisition of Petrovera Resources had a positive impact on our results from the date of closing on May 10, 2005. The Petrovera contribution is partially reflected in the second quarter of 2005 (52 days of production) and is fully reflected in the following periods. Another factor that has influenced our results over the past several quarters is higher operating expenses on our working interest properties, which currently comprise about one-fifth of our total production volumes. Rising costs have been experienced industry wide and particularly in Alberta where strong economic growth and oil sands development have created increased demand for people and services. However, the effect of higher costs on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.

The accompanying table illustrates the fluctuations in pricing experienced over the past eight quarters and the resulting effect on our financial results. Additional information about our quarterly results is provided in our four interim reports for 2006, copies of which are available on SEDAR or on our website.

QUARTERLY REVIEW

	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial *($000s, except as noted)*								
Revenue, net of royalty expenses	31,765	36,550	36,998	33,923	43,364	42,867	27,992	19,170
Funds generated from operations	27,394	31,692	32,565	28,198	38,694	38,893	24,344	16,103
Per Trust Unit *($)*	0.56	0.65	0.66	0.58	0.79	0.79	0.59	0.51
Distributions to Unitholders	23,594	26,521	26,502	26,483	31,366	22,527	17,981	12,936
Per Trust Unit *($)* [1]	0.48	0.54	0.54	0.54	0.64	0.46	0.41	0.41
Payout ratio *(%)*	86	84	81	94	81	58	74	80
Net income	9,545	12,728	14,142	8,766	18,747	19,373	10,858	9,368
Per Trust Unit, basic and diluted *($)*	0.19	0.26	0.29	0.18	0.38	0.40	0.26	0.30
Property and royalty acquisitions	–	5,382	–	–	–	–	351,705	–
Development expenditures	3,766	4,649	1,430	1,601	1,631	4,059	1,215	1,077
Long-term debt	100,000	98,000	96,000	105,000	107,000	118,000	120,000	27,000
Trust Units outstanding								
Weighted average *(000s)*	49,139	49,103	49,068	49,032	48,996	48,961	41,489	31,544
At quarter end *(000s)*	49,174	49,139	49,103	49,067	49,032	48,996	48,960	31,567
Operating *($/boe, except as noted)*								
Daily production *(boe/d)*	8,313	8,335	8,212	8,794	8,739	8,974	7,279	5,502
Average selling price	41.44	48.95	50.27	43.78	54.95	52.61	42.42	39.47
Operating netback	38.57	44.92	47.08	40.18	51.56	49.89	39.61	36.18
Operating expenses	2.95	2.75	2.43	2.68	2.38	2.03	2.54	2.53
Working interest properties	13.86	11.88	11.51	11.26	12.06	10.35	11.00	7.59
General and administrative expenses	1.44	1.32	1.79	2.69	1.52	1.17	1.42	2.55
Benchmark Prices								
WTI crude oil *(US$/bbl)*	60.26	70.48	70.70	63.45	60.02	63.19	53.20	49.84
Exchange rate *(US$/Cdn$)*	0.89	0.89	0.89	0.87	0.85	0.83	0.80	0.82
Edmonton Par crude oil *(Cdn$/bbl)*	64.48	79.08	78.55	68.96	71.17	76.51	65.76	61.45
Light/heavy oil differential *(Cdn$/bbl)*	18.80	20.14	17.43	28.57	28.14	20.79	24.17	22.48
Bow River Hardisty crude oil *(Cdn$/bbl)*	45.69	58.94	61.11	40.39	43.03	55.72	41.59	38.97
AECO natural gas *(Cdn$/Mcf)*	6.36	6.03	6.27	9.27	11.68	8.17	7.38	6.69
Unit Trading Performance								
High *($)*	19.80	23.06	21.70	22.20	18.98	19.30	17.63	18.49
Low *($)*	12.43	18.50	18.02	18.44	15.15	15.99	14.25	15.50
Close *($)*	14.81	19.00	21.00	19.50	18.81	18.68	15.99	16.10
Volume *(000s)*	13,867	5,153	5,336	11,155	7,611	9,980	8,311	2,418

1 Based on the number of Trust Units issued and outstanding at each record date.

PRODUCTION

Our production base is geographically widespread throughout western Canada, with the majority of properties located in Alberta. Annual production was 10% higher than last year, boosted by the Petrovera acquisition that occurred midway through the second quarter of 2005. Production from working interest wells increased 7%, and royalty production rose 11%. Seventy-eight percent of our 2006 production came from royalty interests. On a boe basis, our production profile for 2006 was 38% natural gas, 4% natural gas liquids (NGL), 20% light and medium oil, and 38% heavy oil.

PRODUCTION SUMMARY

(boe/d)	**2006**	2005	2004
Royalty interest properties	**6,530**	5,885	3,711
Working interest properties	**1,882**	1,751	1,877
Total	**8,412**	7,636	5,588

AVERAGE DAILY PRODUCTION BY PRODUCT TYPE

	2006	2005	2004
Light and medium oil *(bbls/d)*	**1,678**	1,648	1,580
Heavy oil *(bbls/d)*	**3,187**	2,840	2,014
NGL *(bbls/d)*	**358**	345	283
Total oil and NGL *(bbls/d)*	**5,223**	4,833	3,877
Natural gas *(Mcf/d)*	**19,138**	16,821	10,270
Oil equivalent *(boe/d)*	**8,412**	7,636	5,588
Total annual production *(Mboe)*	**3,070**	2,787	2,045
Potash *(tonnes/d)*	**10.5**	9.7	7.6

PRODUCTION RECONCILIATION

(boe/d)	Royalty Interest Properties	Working Interest Properties	**Total Trust**
2005 average daily production rate	5,885	1,751	**7,636**
2005 activities, full year impact	1,803	417	**2,220**
2006 development	318	287	**605**
2006 acquisitions	–	45	**45**
Natural decline	(1,476)	(618)	**(2,094)**
2006 average daily production rate	6,530	1,882	**8,412**

PRODUCT PRICES

WTI crude oil prices averaged US$66.22 per barrel in 2006, up 17% from last year. However, since peaking in mid-July, WTI crude prices have declined on lower demand, a calmer-than-expected hurricane season, and an easing of concerns that global tensions would disrupt supply. A stronger Canadian currency during 2006 offset a portion of the economic benefit of higher average oil prices. As a result, average Edmonton Par crude oil prices rose only 6%.

Of particular relevance for Freehold are the markets for heavy oil and prices for the benchmark Bow River Hardisty stream (24.9° API), which is a close proxy for our average oil realizations. The differential between light and heavy oil has a significant impact on our realizations, as approximately 38% of our total boe production is heavy oil. As a result of a global surplus of heavy crude and lack of upgrading capacity in North America, we have witnessed considerable volatility in light/heavy oil differentials over the

past several quarters. Only certain refineries are configured to process heavy oil and their processing capacity is limited. However, new pipeline access was added in 2006, including the start-up of the Enbridge Spearhead pipeline on March 1, and a pipeline reversal enabling Alberta heavy oil to be shipped from Cushing, Oklahoma to Irving, Texas for processing. These new pipelines have expanded the market for heavy oil, and we have benefited from a significant narrowing of the price spread, with Bow River Hardisty prices up 15% higher year-over-year.

Natural gas prices tend to be more volatile than oil prices due to supply and demand factors within North America, and this was the case in 2006. Natural gas prices averaged $6.98 per Mcf, 18% lower than 2005. Since the beginning of 2006, natural gas prices have weakened significantly as a warmer than normal winter enabled gas storage levels to build and remain above seasonal levels.

Longer-term, industry fundamentals remain positive. However, ample inventories, a mild winter, and a slowing U.S. economy could further depress commodity prices in the near term.

AVERAGE BENCHMARK PRICES

	2006	2005	2004
WTI crude oil *(US$/bbl)*	**66.22**	56.56	41.40
Exchange rate *(US$/Cdn$)*	**0.8818**	0.8260	0.7698
Edmonton Par crude oil *(Cdn$/bbl)*	**72.77**	68.72	52.54
Bow River Hardisty crude oil *(Cdn$/bbl)*	**51.53**	44.83	37.60
Light/heavy oil differential *(Cdn$/bbl)*	**21.23**	23.90	14.94
AECO natural gas *(Cdn$/Mcf)*	**6.98**	8.48	6.79

Source for commodity prices: Canadian Association of Petroleum Producers.

Freehold's average selling prices reflect product quality and transportation differences from benchmark prices. Our prices were negatively affected by the decline in natural gas prices and a stronger Canadian dollar compared with last year. On a boe basis, our average price realizations were 5% lower in 2006.

AVERAGE SELLING PRICES

	2006	2005	2004
Oil *($/bbl)*	**50.24**	46.65	38.08
NGL *($/bbl)*	**50.29**	50.58	37.29
Oil and NGL *($/bbl)*	**50.25**	46.93	38.03
Natural gas *($/Mcf)*	**6.54**	8.55	6.28
Oil equivalent *($/boe)*	**46.07**	48.53	37.91
Potash *($/tonne)*	**220.13**	213.28	167.37

MARKETING AND HEDGING

Our royalty lands consist of a large number of royalty properties, with generally small volumes per property. A provision of the leases calls for our natural gas to be marketed with the lessees' production. Historically, we have chosen to market our oil production in the same manner, although some of our leases allow us to take our oil production in kind, and we have chosen to do so to speed up receipt of royalty income. As at December 31, 2006, approximately 28% of our royalty oil production was being marketed by Freehold using 30-day contracts.

We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing.

Our production was unhedged during 2006, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our board of directors.

REVENUE

We receive revenue from more than 200 industry operators. Gross revenue of $143.1 million in 2006 was 4% higher than in 2005, as higher production volumes and higher oil prices offset the decline in natural gas prices. The accompanying table demonstrates the net effect of price and volume variances on gross revenue.

GROSS REVENUE VARIANCES

($000s)	**2006 vs. 2005**	2005 vs. 2004
Oil and NGL		
Production increase	**7,149**	16,191
Price increase	**5,844**	12,637
Net increase	**12,993**	28,828
Natural gas		
Production increase	**5,531**	20,345
Price increase (decrease)	**(12,322)**	8,531
Net increase (decrease)	**(6,791)**	28,876
Other revenue increase (decrease) [1]	**(49)**	719
Gross revenue increase	**6,153**	58,423

1 Other revenue includes potash revenue, sulphur revenue, lease rentals, processing fees, and interest income.

REVENUE

($000s)	**2006**	2005	2004
Gross revenue	**143,067**	136,914	78,491
Royalty expenses [1]	**(3,831)**	(3,591)	(2,977)
Net revenue	**139,236**	133,323	75,514

1 Net of Alberta Royalty Credit. Royalty expenses are incurred only on working interest production.

EXPENSES

ROYALTIES PAID

Oil and gas producers pay royalties to the owners of mineral rights from whom they hold leases. These are paid to the Crown (provincial and federal government) and freehold mineral title owners. Royalty expense rates are linked to commodity prices and the level of oil and gas sales. In 2006, royalties paid on production relating to ownership in working interest properties totalled $3.8 million, or 3% of gross revenue.

ROYALTY EXPENSES

($000s, except as noted)	**2006**	2005	2004
Working interest properties [1]	**3,831**	3,591	2,977
Per boe *($)*	**5.58**	5.62	4.33
Royalty interest properties [2]	**–**	–	–
Per boe *($)*	**–**	–	–
Total royalty expenses [1]	**3,831**	3,591	2,977
Per boe *($)*	**1.25**	1.29	1.46
As a percentage of gross revenue	**3%**	3%	4%

1 Net of Alberta Royalty Credit.
2 We do not incur royalty expenses on production from our royalty interest properties. As the royalty owner, we receive the royalty as income from other companies.

OPERATING EXPENSES

Operating expenses are comprised of direct costs incurred and costs are allocated among oil, natural gas, and NGL production. Operating recoveries associated with operated properties are excluded from operating costs and accounted for as a reduction to general and administrative costs. On our working interest properties, which accounted for 22% of our production in 2006, operating expenses per boe of production rose 18%. With industry activity at record levels, the demand for oilfield goods and services is intense, and the energy sector has been experiencing cost inflation. The majority of our working interest properties are operated by others, and we expect that the operators will initiate cost reduction measures to manage the impact of inflation.

As 78% of our production was from royalties in 2006, we were somewhat sheltered from the effects of increased costs because royalty production is not encumbered by these expenses. Operating costs of our total operations (including our royalty lands) were $2.71 per boe, up 16% year over year.

OPERATING EXPENSES

($000s, except as noted)	**2006**	2005	2004
Working interest properties	**8,309**	6,530	5,860
Per boe *($)*	**12.09**	10.22	8.53
Royalty interest properties [1]	–	–	–
Per boe *($)*	–	–	–
Total operating expenses	**8,309**	6,530	5,860
Per boe *($)*	**2.71**	2.34	2.87
As a percentage of gross revenue	**6%**	5%	7%

1 We do not incur operating costs on our royalty interest properties.

GENERAL AND ADMINISTRATIVE EXPENSES

We have significant land administration, accounting and auditing requirements to administer and collect royalty payments. This includes systems to track lessee activity on the royalty lands. In 2006, G&A costs totalled $5.6 million, including $3.7 million charged by the Manager for time and direct costs incurred on behalf of the Trust. On a per boe basis, G&A expenses were 15% higher year-over-year. General and administrative expenses have remained between 3% and 4% of gross revenue for the past three years.

An increase in the Manager's staff levels following the Petrovera acquisition, higher stock exchange listing fees due to additional Trust Units outstanding, rising costs associated with financial reporting and regulatory compliance, and higher directors' fees all contributed to higher G&A expenses in 2006. We expensed $450,000 for the Trust's proportionate share of the Manager's annual bonus plan. We also continued the work of evaluating internal controls; the anticipated cost of the project is expected to reach $500,000, of which $325,000 has been incurred to date.

We recorded a non-cash expense of $247,000 (with a corresponding increase to contributed surplus) as unit based compensation relating to the grant of 12,559 deferred trust units to non-management directors during 2006. G&A also included a non-cash charge of $43,000 for the Trust's proportionate share of the Manager's LTIP for 2006 (see New Accounting Policies).

GENERAL AND ADMINISTRATIVE EXPENSES

($000s, except as noted)	**2006**	2005	2004
Gross general and administrative expenses	**5,670**	4,479	3,610
Less overhead recoveries [1]	**(89)**	(87)	(108)
Net general and administrative expenses	**5,581**	4,392	3,502
Per boe *($)*	**1.82**	1.58	1.71
As a percentage of gross revenue	**4%**	3%	4%

1 Because we do not operate any of our royalty production, our overhead recoveries are minimal.

MANAGEMENT FEES

The Manager of the Trust receives a management fee paid in Trust Units. The issue of 17.4 million Trust Units in May 2005 resulted in a pro-rata increase in the management fee, in accordance with the management agreement. In 2006, we issued 142,616 Trust Units in payment of the management fee (2005 – 123,825 Trust Units). The ascribed value is based on the closing price of the Trust Units at the end of each quarter.

MANAGEMENT FEES

	2006	2005	2004
Trust Units issued in payment of management fees	**142,616**	123,825	90,000
Ascribed value of management fees *($000s)* [1]	**2,649**	2,178	1,428
Per boe *($)*	**0.86**	0.78	0.70
As a percentage of gross revenue	**2%**	2%	2%
As a percentage of distributions	**3%**	3%	3%

1 The ascribed value of the management fees is based on the closing Trust Unit price at the end of each quarter.

INTEREST EXPENSES

Additional debt assumed in May 2005 to acquire Petrovera Resources has resulted in increased interest expenses.

INTEREST EXPENSES

($000s, except as noted)	2006	2005	2004
Interest on operating line	**10**	13	7
Interest on long-term debt	**5,184**	3,145	628
Net interest expense	**5,194**	3,158	635
Per boe *($)*	**1.69**	1.13	0.31
As a percentage of gross revenue	**4%**	2%	1%

NETBACK

Netback, calculated on a boe basis, represents the cash margin on the sale of oil and gas. Operating netback is calculated by subtracting royalty expenses and operating costs from revenues.

OPERATING NETBACK

($ per boe)	2006	2005	2004
Royalty interest properties	**45.81**	50.01	38.78
Working interest properties	**31.64**	30.30	24.71
Total Trust	**42.64**	45.49	34.05

OPERATING NETBACK BY PRODUCT TYPE

	2006	2005	2004
Light and medium oil *($/bbl)*	**57.03**	56.02	41.17
Heavy oil *($/bbl)*	**38.29**	34.31	26.87
Natural gas *($/Mcf)*	**6.24**	8.13	5.75
NGL *($/bbl)*	**47.08**	47.14	33.55
Combined *($/boe)* [1]	**42.64**	45.49	34.05

1 Includes potash revenue, sulphur revenue and other.

On the majority of our production, we receive royalty income from gross production revenue (revenue before any royalty expenses and operating costs are deducted). We do not incur development expenditures, operating expenses, abandonment, or site restoration expenses on our royalty production. The accompanying netback analysis demonstrates the positive effect of this royalty advantage on our cash margins.

2006 NETBACK ANALYSIS

($ per boe)	Royalty Interest Properties	Working Interest Properties	**Total Trust**
Gross revenue [1]	45.81	49.31	**46.60**
Royalty expenses [2]	–	(5.58)	**(1.25)**
Net revenue	45.81	43.73	**45.35**
Operating expenses	–	(12.09)	**(2.71)**
Operating netback	45.81	31.64	**42.64**
General and administrative expenses	(1.84)	(1.74)	**(1.82)**
Interest expense	(1.95)	(0.81)	**(1.69)**
Income and capital taxes	–	(0.42)	**(0.09)**
Unit-based compensation	0.09	0.09	**0.09**
Expenditures on reclamation	–	(0.44)	**(0.10)**
Funds generated from operations	42.12	28.33	**39.03**
Reclamation fund contributions	–	(0.22)	**(0.05)**
Development expenditures	–	(16.66)	**(3.73)**
Changes in debt	(6.06)	10.83	**(2.28)**
Net acquisition cost	–	(7.83)	**(1.75)**
Changes in working capital	2.36	2.36	**2.36**
Investor netback [3]	38.42	16.80	**33.58**

1 Includes potash revenue, sulphur revenue and other.
2 Net of Alberta Royalty Credit.
3 Excludes management fee paid in Trust Units.

DEPLETION AND DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION

Oil and gas properties and royalty interests, including the cost of production equipment, future capital costs associated with proved reserves, and the capitalized portion of asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable (see Accounting Policies and Critical Accounting Estimates). Reserves are independently evaluated annually. For the first three quarters of 2006, the estimate of proved reserves was based on the independent evaluation dated December 31, 2005, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2006.

In 2006, depletion and depreciation on property, plant and equipment and accretion on the asset retirement obligation totalled $72.1 million ($23.50 per boe), up from $57.2 million ($20.52 per boe) last year. The increase reflects the addition of petroleum and natural gas interests from the Petrovera acquisition in May 2005 at a higher cost than our historical average.

Our ceiling test calculation, performed at December 31, 2006, resulted in no impairment loss. The future prices used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our quality, transportation, and contract differences.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES

($000s, except as noted)	**2006**	2005	2004
Depletion and depreciation	**71,874**	56,938	25,661
Accretion of asset retirement obligation	**257**	252	232
Total depletion, depreciation and accretion expenses	**72,131**	57,190	25,893
Per boe *($)*	**23.50**	20.52	12.66
As a percentage of gross revenue	**50.4%**	41.8%	33.0%

RECLAMATION FUND

We are liable for our share of ongoing environmental obligations and the ultimate reclamation of our working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from funds generated from operations. At December 31, 2006, our estimated undiscounted share of future environmental and reclamation obligations for the working interest properties is approximately $12.2 million.

In 1996, we established a reclamation fund to ensure that required funds are available for future reclamation of working interest wells and facilities once they have reached the end of their economic lives. The fund consists of cash invested in an interest-bearing account and is funded by quarterly cash payments. We contributed $455,000 in cash and interest to the fund during 2006 and withdrew $302,000, which was spent on reclamation activities. At December 31, 2006, the fund had a balance of $2.1 million. For 2007, quarterly contributions will remain at $100,000 to ensure that future obligations can be met.

RECLAMATION FUND SUMMARY

($000s)	Cumulative Since Inception	**2006**	2005	2004
Reclamation fund, beginning balance	–	**1,964**	1,646	1,289
Reclamation fund contributions	2,982	**455**	422	414
Expenditures on reclamation	(865)	**(302)**	(104)	(57)
Reclamation fund, ending balance	2,117	**2,117**	1,964	1,646

TAXES

Freehold Royalty Trust is a taxable trust under the *Income Tax Act* (Canada). We distribute substantially all of our taxable income to Unitholders. By doing so, exposure to current tax at the trust level is eliminated. In addition, we are exempt from future income taxes because we are contractually committed to distribute all of our income to Unitholders.

Capital taxes consist primarily of the Saskatchewan Capital Tax applied to both taxable capital and gross revenues in that province. Our subsidiary, Freehold Resources Ltd., is a Canadian corporation subject to tax in various jurisdictions. Freehold Resources Ltd. can deduct royalty payments to us in determining its taxable income, and is generally liable for income taxes on its 1% residual interest. Freehold Resources Ltd. is subject to federal and capital tax in any jurisdiction (federal and provincial) in which it has a permanent establishment.

TAXES

($000s)	2006	2005	2004
Provincial capital tax	**253**	120	116
Current income tax	**38**	985	1,031
Total	**291**	1,105	1,147

TAX POOLS

($000s)	2006	2005	2004
Canadian oil and gas property expense	**133,879**	144,470	160,338
Canadian development expense	**10,852**	8,058	5,971
Canadian exploration expense	**–**	–	–
Capital cost allowance	**10,103**	7,516	6,571
Unit issue costs	**6,641**	8,854	269
Non-capital loss carryovers	**96**	–	–
Total [1]	**161,571**	168,898	173,149

1 These amounts, subject to review by Canada Revenue Agency, represent our direct tax pools as well as the tax pools of our subsidiary, Freehold Resources Ltd.

On a consolidated basis, the Trust's carrying value for book purposes exceeds the amount available for tax purposes by $278 million.

UNITHOLDER TAXATION

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. By using two principal deductions – the Canadian Oil and Gas Property Expense and the Resource Allowance – cash distributions in the Trust's initial years were sheltered from income tax. Over time, as a result of a general reduction in tax pools available for future claims, an increasing percentage of the annual distributions become taxable.

For purposes of the *Income Tax Act* (Canada), Freehold Royalty Trust is treated as a mutual fund trust. Each year, we file a T3 income tax return with the taxable income allocated to and made taxable in the hands of Unitholders. This taxable income is allocated, on T3 supplementary forms, to each Unitholder who was entitled to distributions for the year. The T3 slip will report the amount in Box 26. This income is taxed as ordinary income.

CANADIAN RESIDENTS

For Canadian tax purposes, 90% of distributions declared in 2006 were taxable as income, unless held in a registered plan, such as a Registered Retirement Savings Plan, a Registered Retirement Income Fund, a Deferred Profit Sharing Plan or a Registered Education Savings Plan.

For 2007, we currently estimate that 100% of distributions to Unitholders will be taxable as other income.

NON-RESIDENTS OF CANADA

Unitholders who are not residents of Canada for income tax purposes are encouraged to seek advice from a qualified tax advisor in their country of residence for the tax treatment of distributions. Distributions paid or payable to non-residents of Canada are subject to a withholding tax of 25% as prescribed by the *Income Tax Act* (Canada). This withholding tax may be reduced in accordance with reciprocal tax treaties. In the case of the Tax Treaty between Canada and the U.S., the withholding tax for U.S. residents is 15%.

UNITED STATES RESIDENTS

For Trust Units held outside a qualified retirement plan, 100% of the distributions should be reported as ordinary dividends unless the Unitholder elects to treat Freehold as a Qualified Electing Fund (QEF), in which case the Unitholder's share of income should be reported as ordinary income. In consultation with our U.S. tax advisors, we believe that Freehold should be classified as a passive foreign investment company (PFIC) under U.S. federal income tax principles. As such, distributions made during 2006 are subject to the provisions of U.S. federal income taxation applicable to a PFIC. To allow Unitholders the ability to make a QEF election, we post annually a PFIC Annual Information Statement on our website. Unitholders should contact their own tax advisors for information on correctly completing Form 8621. This information is not available from Freehold.

Additional income tax information for Unitholders is available on our website.

PROPOSED TAXATION OF INCOME TRUSTS

On October 31, 2006, the Federal Minister of Finance announced a proposal to apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and to treat such distributions as dividends to the unitholders. On December 21, 2006, draft legislation was released to implement the proposed tax changes pursuant to which, commencing January 1, 2011 (provided Freehold only experiences "normal growth" and no "undue expansion" before then) certain distributions from Freehold which would have otherwise been taxed as ordinary income generally will be characterized as dividends in addition to being subject to tax at corporate rates at Freehold's level.

The long-term effect of the proposed tax changes on Freehold is yet to be determined. However, assuming the changes are ultimately enacted in the form currently proposed, the implementation of such legislation would be expected to result in adverse tax consequences to Freehold and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact cash distributions from Freehold starting in 2011. It is not known at this time when the proposed tax changes will be enacted by Parliament, if at all, or whether they will be enacted in the form currently proposed (See Liquidity and Capital Resources).

DISTRIBUTIONS

Distributions declared in 2006 totalled a record $2.10 per Trust Unit. The weakening in commodity prices during 2006 prompted our Board of Directors to reduce the monthly distribution rate to $0.15 per Trust Unit effective with the December 15 payment.

2006 DISTRIBUTIONS DECLARED

Record Date	Payment Date	Distribution ($ per Trust Unit)
January 31, 2006	February 15, 2006	**0.18**
February 28, 2006	March 15, 2006	**0.18**
March 31, 2006	April 15, 2006	**0.18**
April 30, 2006	May 15, 2006	**0.18**
May 31, 2006	June 15, 2006	**0.18**
June 30, 2006	July 15, 2006	**0.18**
July 31, 2006	August 15, 2006	**0.18**
August 31, 2006	September 15, 2006	**0.18**
September 30, 2006	October 15, 2006	**0.18**
October 31, 2006	November 15, 2006	**0.18**
November 30, 2006	December 15, 2006	**0.15**
December 31, 2006	January 15, 2007	**0.15**
Total		**2.10**

The following reconciliation shows the deductions from cash provided by operating activites to arrive at cash available for distribution. Since inception, we have declared distributions totalling $14.30 per Trust Unit.

DISTRIBUTIONS TO UNITHOLDERS

($000s)	**2006**	2005	2004
Cash provided by operating activities	**130,934**	97,067	64,051
Net reclamation fund contribution	**(153)**	(318)	(357)
Development expenditures	**(11,446)**	(7,982)	(5,823)
Debt additions (repayment)	**(7,000)**	80,000	9,000
Proceeds from Trust Unit issuance	**–**	258,935	–
Property and royalty acquisitions	**(5,382)**	(351,705)	(13,061)
Cash available for distribution	**106,953**	75,997	53,810
DISTRIBUTIONS TO UNITHOLDERS	**103,100**	84,810	54,490
Accumulated, beginning of period	**383,024**	298,214	243,724
Accumulated, end of period	**486,124**	383,024	298,214
DISTRIBUTIONS PER TRUST UNIT *($)* [1]	**2.10**	1.92	1.70
Accumulated, beginning of period	**12.20**	10.28	8.58
Accumulated, end of period	**14.30**	12.20	10.28

1 Based on the number of Trust Units issued and outstanding at each record date.

Cash available for distribution is typically less than cash provided by operating activities as we retain funds to finance reclamation fund contributions, development expenditures, minor acquisitions and debt repayment. Differences between cash available for distribution and actual cash distributions result from changes in working capital. In 2005, the difference between cash available for distribution and actual distributions is the result of distributions declared late in 2005 not being payable to Unitholders until February 2006.

PAYOUT RATIO [1]

($ per Trust Unit, except as noted)	**2006**	2005	2004
Funds generated from operations [2]	**2.44**	2.76	2.04
Distributions declared [3]	**2.10**	1.92	1.73
Payout ratio [1]	**86%**	72%	85%

1 Distributions declared as a percentage of funds generated from operations.
2 Based on the weighted average number of Trust Units outstanding during the period.
3 Based on the number of Trust Units issued and outstanding at each record date.

Distributions in 2006 represented 86% of funds generated from operations versus 72% in 2005. The lower payout ratio in 2005 indirectly reflects the step change in our production volumes with the Petrovera acquisition in 2005. The increase in royalty interest production and high product prices at year-end required a corresponding increase in our accounts receivables caused by the normal lag in receiving royalty revenue. The increase in accounts receivables was included in changes in working capital. Since inception, our payout ratio has averaged 82%.

LIQUIDITY AND CAPITAL RESOURCES

In conjunction with the Petrovera acquisition in 2005, we expanded our credit facilities from $65 million to $165 million. These credit facilities were used to fund $93 million of the purchase price for the acquisition, inclusive of transaction costs. During 2006, we repaid $7 million of long-term debt with funds generated from operations. At December 31, 2006, we had no short-term debt outstanding and long-term debt was $100 million. We had working capital of $9.1 million, resulting in net debt of $91 million. In addition, we

had accrued $129,000 as a long term liability relating to incentive compensation pursuant to the Manager's LTIP (see General and Administrative Expenses). We currently have $65 million of available capacity under our credit facilities.

DEBT ANALYSIS

($000s)	2006	2005	2004
Long-term debt	100,000	107,000	27,000
Short-term debt (operating line)	–	–	–
Total debt	100,000	107,000	27,000
Less: working capital	9,050	16,281	4,128
Net debt obligations	90,950	90,719	22,872

At December 31, 2006, our ratio of net debt (total debt less positive working capital) to trailing funds generated from operations was 0.8 to 1, unchanged from the end of 2005.

FINANCIAL LEVERAGE AND COVERAGE RATIOS [1]

	2006	2005	2004
Net debt to trailing funds generated from operations *(times)*	0.8	0.8	0.4
Distributions to interest expense *(times)*	19.9	26.9	86.0
Net debt to distributions *(times)*	0.9	1.1	0.4
Net debt to net debt plus equity *(%)*	21	19	12

1 Funds generated from operations, distributions, and interest expense are 12-months trailing.

The following table outlines our sources and uses of funds during the past three years.

SOURCES AND USES OF FUNDS

($000s)	2006	2005	2004
Sources of funds			
Funds generated from operations	119,849	118,034	64,313
Equity issued, net of costs	–	258,935	–
Change in non-cash working capital	12,832	(20,990)	(212)
	132,681	355,979	64,101
Uses of funds			
Debt reduction (addition)	7,000	(80,000)	(9,000)
Net reclamation fund contributions	153	318	357
Development expenditures	11,446	7,982	5,823
Property acquisitions, net of costs	5,382	351,705	13,061
Distributions declared	108,471	75,848	53,851
Change in cash	229	126	9
	132,681	355,979	64,101

The following table illustrates the changes in working capital at the end of each quarter during 2006.

COMPONENTS OF WORKING CAPITAL [1]

($000s)	December 31 2006	September 30 2006	June 30 2006	March 31 2006	December 31 2005
Cash	**421**	**585**	**245**	**38**	192
Accounts receivable	**29,850**	**28,311**	**28,051**	**32,125**	35,728
Current assets	**30,271**	**28,896**	**28,296**	**32,163**	35,920
Distributions payable to Unitholders	**(7,376)**	**(8.845)**	**(8,839)**	**(8,832)**	(12,748)
Accounts payable and accrued liabilities	**(13,845)**	**(12,498)**	**(9,107)**	**(9,042)**	(6,891)
Current liabilities	**(21,221)**	**(21,343)**	**(17,946)**	**(17,874)**	(19,639)
Working capital [1]	**9,050**	**7,553**	**10,350**	**14,289**	16,281

1 Working capital is comprised of current assets minus current liabilities.

The increased royalty interest production from the Petrovera acquisition in 2005 required a corresponding increase in our accounts receivables, caused by the normal time lag in receiving royalty revenue. The dollar amount of receivables also increased due to higher commodity prices. Accounts payable at December 31, 2006 were higher as a result of the significant amount of capital spent in 2006 and the timing of invoices. In addition, distributions payable to Unitholders at December 31, 2005 included a special distribution of $0.08 per Trust Unit as a result of excess taxable income earned in 2005.

ACQUISITIONS AND DEVELOPMENT EXPENDITURES

Effective July 1, 2006, we purchased a 5.2% working interest in the Wildmere Lloydminster 'A' Pool Unit No. 1, in which we also have a 2.5% royalty interest. The $5.4 million acquisition was funded from funds generated from operations. In 2005, we completed the Petrovera acquisition for $351.7 million, for which the Manager received an acquisition fee of $5.3 million. This fee was charged to petroleum and natural gas interests as part of the properties acquired. The Manager's acquisition fee was eliminated effective January 1, 2006.

We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests, while maintaining a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders.

PROPERTY AND ROYALTY ACQUISITIONS

($000s)	2006	2005	2004
Purchase price	**5,500**	353,713	13,125
Acquisition fee [1]	**–**	5,306	197
Interest expense	**–**	5,349	–
Evaluation and legal costs	**–**	2,303	30
Purchase price adjustments [2]	**(118)**	(14,966)	(471)
Additions to petroleum and natural gas interests	**5,382**	351,705	12,881
Working capital	**–**	–	180
Net acquisition costs	**5,382**	351,705	13,061

1 The 1.5% acquisition fee payable to the Manager for acquisitions completed on behalf of the Trust was eliminated effective January 1, 2006.
2 Net revenue from effective date to closing.

Our development expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to the determination of distributions to Unitholders. The amount of expenditures to be deducted is limited to 15% of annual funds generated from operations. As we do not incur development expenditures on our royalty lands, our capital requirements are modest, relative to most energy trusts. In 2006, development expenditures of $11.4 million amounted to 9.6% of

funds generated from operations. For 2007, we have approved a development budget of $8.0 million with respect to our working interest properties.

DEVELOPMENT EXPENDITURES

($000s)	2006	2005	2004
Development drilling	**7,584**	5,379	3,451
Plant and facilities	**3,862**	2,603	2,372
Total development expenditures	**11,446**	7,982	5,823
As a percentage of funds generated from operations	**9.6%**	6.8%	9.1%

POTENTIAL IMPACT OF PROPOSED TAXATION

The proposed taxation of income trusts may reduce the value of our Trust Units, which would be expected to increase our cost of raising capital in the public capital markets. In addition, the proposed tax changes are expected to substantially eliminate the competitive advantage that Freehold and other Canadian trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner and place Freehold and other Canadian trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation.

The proposed tax changes are also expected to make our Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for Freehold to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize Freehold's legal and tax structure to substantially mitigate the expected impact of the proposed tax changes.

Further, the proposed tax changes provide that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being "revisited", presumably with the loss of the benefit to us of that transitional period. As a result, the adverse tax consequences resulting from the proposed tax changes could be realized sooner than January 1, 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by "normal growth" in this context. "Normal growth" would include equity growth within certain "safe harbour" limits, measured by reference to market capitalization as of the end of trading on October 31, 2006. Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% in each of the following three years. Moreover, the yearly limits are cumulative, so that any unused limit for a period carries over into the subsequent period.

Our market capitalization as of the close of trading on October 31, 2006 was approximately $928.7 million, which means our "safe harbour" equity growth amount for the period ending December 31, 2007 is approximately $371.5 million, and for each of calendar 2008, 2009 and 2010 is an additional $185.7 million with an ultimate total equity growth amount of no more than $928.7 million.

While these guidelines are such that it is unlikely they would affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transitional period, they could adversely affect the cost of raising capital and our ability to undertake more significant acquisitions.

TRUST UNITS OUTSTANDING

As at March 14, 2007, there were 49,174,197 Trust Units outstanding, unchanged from December 31, 2006. In May 2005, we issued 17.4 million Trust Units in association with the Petrovera acquisition.

At the Annual and Special Meeting of Unitholders held on May 10, 2006, Unitholders approved a deferred trust unit plan for non-management directors whereby fully vested deferred trust units are granted annually. Subsequently, the Board allocated 1,595 deferred trust units to each eligible director and 3,190 deferred trust units to the Chair of the Board. Under this plan, distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. As at December 31, 2006, there were 12,559 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

On January 1, 2007, the Board approved annual grants for 2007 totalling 14,181 deferred trust units, allocating 2,026 to each eligible director and 4,051 to the Chair of the Board. As at March 14, 2007, there were 27,303 deferred trust units outstanding.

TRUST UNITS OUTSTANDING

	2006	2005	2004
Weighted average			
Basic	**49,085,795**	42,812,470	31,488,355
Diluted	**49,093,609**	42,812,470	31,488,355
At December 31	**49,174,197**	49,031,581	31,544,236

INDUSTRY TRENDS

Industry wide, just over 22,000 wells were drilled in western Canada during 2006, up 1% from 2005. We anticipate that lower commodity prices will reduce drilling activity in 2007, particularly in natural gas regions. Drilling has already shifted to more oil-weighted targets as lower natural gas prices have made the economics of shallow gas and coal bed methane activity less attractive for producers. Nonetheless, industry activity in western Canada, particularly in the oil sands, remains robust and the demand for people and oilfield services is unprecedented. The oil and gas industry continues to experience higher costs, as well as a severe shortage of experienced professionals and skilled tradespeople.

Of great concern to us is the growing surplus of heavy crude and lack of upgrading capacity, which may have a significant negative impact on our price realizations due to our heavier product mix. Bitumen production from Alberta's oil sands is expected to increase significantly over the next several years. As a result, markets for heavy oil and bitumen will be somewhat uncertain in the future. Supply and demand imbalances could result in the heavy oil price differential remaining well above historical averages.

We view continuing development on our royalty lands as an essential part of our future success. Drilling on Freehold's lands was down from last year's record, although 2006 was still the second best year in our 10-year history with 851 gross (26.2 equivalent net) wells drilled on our lands. Of note, there were 119 (6.1 equivalent net) licensed drilling locations on our royalty lands at year-end 2006, up from 92 (4.6 equivalent net) locations at the end of 2005. The higher number of drilling licences is evidence of the ongoing development potential of our royalty lands.

BUSINESS RISKS AND MITIGATING STRATEGIES

The operations of an energy trust are subject to virtually the same industry risks and conditions faced by conventional oil and gas companies. The most significant of these include, but are not limited to:

- fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- variations in currency exchange rates;
- imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and we and our lessees may not be able to replace these reserves on an economic basis;
- industry activity levels and intense competition for land, goods and services and qualified personnel;
- stock market volatility and the ability to access sufficient capital from internal and external sources;
- operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- changes in government regulations and taxation; and
- safety and environmental risks.

As a royalty trust, we are also subject to the following risks:

- Fifteen royalty payors account for about two-thirds of our royalty income, and changes to their businesses may have a significant effect on our results.
- Higher prime borrowing rates, which may increase interest expense on our debt, and which may make fixed income investments more attractive to investors of Trust Units.

We employ the following strategies to mitigate these risks:

- Our diversified revenue stream limits the size of any one property with respect to our total assets.
- We are not liable for abandonment and reclamation costs on our royalty lands.
- Due to our high percentage of royalty lands, we have one of the lowest all-in cost structures of our peer group. In addition, we maintain a focus on controlling direct costs to maximize profitability.
- We maintain an aggressive auditing program to ensure that royalties are paid on our production from our lands, that our royalties paid are in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. During 2006, our audit staff issued audit exception queries amounting to $5.9 million, bringing the total amount of audit exception queries since 1997 to $22.2 million, $17.1 million of which has been recovered.
- We adhere to strict investment criteria for acquisitions, seeking royalty and working interest properties that have high netbacks, long reserve life, low risk development potential and product diversification.
- We market our products to a diverse range of buyers. Currently, we do not have any commodity price, exchange rate or interest rate hedging programs in place and do not anticipate a change in this policy.
- We employ a qualified team of oil and gas professionals with many years of experience and knowledge in managing our assets.
- We maintain levels of liability insurance that meet or exceed industry standards.
- We employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of funds generated from operations to debt repayment.

HEALTH, SAFETY AND ENVIRONMENT

Freehold is a member of the Canadian Association of Petroleum Producers (CAPP). We promote the development and use of a systematic approach to continuously improve environment, health, safety and social performance. We encourage our operators to participate and excel in the CAPP Stewardship Program, by aligning their operations with industry best practices and communicating clearly that meeting or exceeding regulatory requirements is expected.

We do not operate any of our oil and gas assets, nor do we have any employees. The employees who manage the affairs of Freehold are employees of Rife Resources Ltd., a private oil and gas company that manages production of approximately 22,000 boe per day on behalf of three entities, including Freehold. Rife has a comprehensive environment, health and safety program to protect the health and safety of its employees, contractors, and the public. For example:

- Since 1995, Rife has participated in the Canadian GHG Challenge Registry, Canada's only voluntary publicly accessible national registry of greenhouse gas baselines, targets, and reductions. Rife was a Gold Champion Level Reporter in the 2006 reporting year.
- In 2006, Rife received a Certificate of Recognition (COR) from Alberta Human Resources and Employment's Partnerships in Health and Safety Program after completing the required independent safety audit. Rife will continue to support the Partnerships program which requires an external audit every three years.
- In 2006, Rife was selected for the Work Safe Alberta 2005 Best Safety Performer Awards for exceptional performance in workplace health and safety. Of 128,000 employers, approximately 350 earned this award.

We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of the working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets as these are the responsibility of the working interest owners. In 1996, we established a reclamation fund to ensure that required funds are available for future reclamation of working interest wells and facilities once they have reached the end of their economic life (see Reclamation Fund).

DISTRIBUTION OUTLOOK

Based on the assumptions in the accompanying table, we estimate that distributions in 2007 will total $1.80 per Trust Unit, with monthly distributions of $0.15 per Trust Unit. Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates, or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 38% of our total boe production is heavy oil. Supply and demand imbalances could keep heavy oil price differentials well above historical averages. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

2007 DISTRIBUTION OUTLOOK

Estimated cash distributions *($/Trust Unit)*	**1.80**
Key Assumptions	
Average daily production, excluding acquisitions (*boe/d)*	7,950
Average WTI oil price *(US$/bbl)*	62.50
Average AECO natural gas price *(Cdn$/Mcf)*	7.25
Average light/heavy oil price differential *(Cdn$/bbl)*	25.00
Average exchange rate *(US$/Cdn$)*	0.90
Average operating costs *($/boe)*	3.00
Average general and administrative costs *($/boe)*	2.10
Development expenditures *($ millions)*	8
Long-term debt at year end *($ millions)*	97
Weighted average Trust Units outstanding *(millions)*	49.2
Payout ratio *(%)*	89
Estimated taxability of distributions, as other income *(%)*	100

The following table provides an analysis of the potential impact key factors may have on distributions to Unitholders, based on our 2007 budget forecast.

SENSITIVITY ANALYSIS

Variables	Change (+/–)	Estimated Change in Distributions to Unitholders	
		($000s)	*($/Trust Unit)*
WTI crude oil price	US$1.00/bbl	1,989	0.04
Light/heavy oil price differential	Cdn$1.00/bbl	1,796	0.04
Natural gas price	Cdn$0.25/Mcf	1,657	0.03
Exchange rate *(US$/Cdn$)*	0.01	1,392	0.03
Interest rates	1%	988	0.02
Oil and NGL production	100 bbls/d	1,584	0.03
Natural gas production	1,000 Mcf/d	2,557	0.05

NEW ACCOUNTING STANDARDS

Three new Canadian accounting standards with respect to comprehensive income (CICA HB 1530), financial instruments (CICA HB 3855), and hedges (CICA HB 3865) were effective January 1, 2007. The new standards will require:

- the identification of any non-financial contracts that may be accounted for as derivatives;
- that all derivatives be carried on the balance sheet at fair value; and
- significant enhancements to the procedures for the documentation, assessment, and measurement of hedging relationships.

As Freehold does not currently have any financial instruments that are affected by these new standards, their adoption will not have any material impact on our results of operations or financial position.

ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Our financial statements are prepared within a framework of GAAP selected by management and approved by our board of directors.

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, oil and gas revenue accruals, asset retirement obligations, and future income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

An estimate is considered a critical accounting estimate if it requires management to make assumptions about matters that are highly uncertain, and if different estimates that could have been used would have a material impact. We continually evaluate the estimates and assumptions. In the normal course, changes are made to assumptions underlying all critical accounting estimates to reflect current economic conditions and updating of historical information used to develop the assumptions. Except as discussed in this Management's Discussion and Analysis, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

RESERVE ESTIMATES, DEPLETION AND CEILING TEST

The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2006. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition is completed. The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material.

We follow the full cost method of accounting for petroleum and natural gas interests. Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in the depletion rate. As at December 31, 2006, the depletion calculation included $2.9 million for estimated future development costs associated with proved undeveloped reserves and excluded $19.4 million for the lower of cost and estimated value of unproved lands.

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The ceiling test estimates were reviewed at year-end to ensure that they are reasonable and supportable in light of current economic conditions. The ceiling test, performed as at December 31, 2006, indicated that the undiscounted future net revenues from proved reserves exceed the net book value of the properties. Accordingly no write down of oil and gas properties is required.

ACCRUALS

Freehold follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. We expect that these accrual estimates will be revised, upwards or downwards, based on the receipt of actual results.

We have no operational control over our royalty lands, and we primarily hold small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, we use government reporting databases and past production receipts to estimate revenue accruals. The increase in royalty interest production with the Petrovera acquisition in May 2005 required a corresponding increase in our revenue accruals. The increase is reflected in higher accounts receivables.

ASSET RETIREMENT OBLIGATIONS

Accounting standards require us to recognize the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. Once the initial asset retirement obligation is measured, it must be adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows that underlie the obligation.

We have no asset retirement obligations on our royalty income properties. Our asset retirement obligations result from the responsibility to abandon and reclaim our net share of all working interest properties. The net present value of our total asset retirement obligation is estimated to be $4.6 million (discounted at a weighted average credit adjusted risk free rate of 6.1%), with the undiscounted value being $12.2 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away.

In determining our asset retirement obligations, we are required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could impact the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

FUTURE INCOME TAXES

We follow the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of future income tax may be greater than or less than the estimates and the differences may be material.

UNIT BASED COMPENSATION

A deferred trust unit plan was established in 2006 for the non-management directors of Freehold whereby fully vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Compensation expense is recognized at market value at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital (see Trust Units Outstanding and General and Administrative Expenses).

Effective January 1, 2006, we began funding a portion of the costs associated with a long-term incentive compensation plan for employees of Rife Resources, the Manager of the Trust (the Manager's LTIP). The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional rights on the date of distribution. As participants in the Manager's LTIP receive a cash payment on a fixed vesting date, compensation expense is determined based on the intrinsic value of the rights at each period end. The valuation incorporates the period end Trust Unit price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with a corresponding increase or decrease in liabilities. The Trust has not incorporated an estimated forfeiture rate for rights that will not vest; rather, the Trust accounts for actual forfeitures as they occur (see General and Administrative Expenses).

INTERNAL CONTROLS AND DISCLOSURE CONTROLS AND PROCEDURES

In compliance with Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, Freehold has filed certificates signed by the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO) that, among other things, deal with the matter of disclosure controls and procedures and internal control over financial reporting.

Disclosure controls and procedures are controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed in regulatory filings is recorded, processed, summarized and reported within the time periods specified and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Management has evaluated the effectiveness of the Trust's disclosure controls and procedures as of March 14, 2007. This evaluation was performed under the supervision of, and with the participation of the CEO and the CFO. It took into consideration Freehold's Disclosure, Insider Trading, Code of Business Conduct and Conflict of Interest, and Whistleblower policies, as well as the functioning of the Manager, the officers, the board of directors, and board committees. In addition, the evaluation covered the processes, systems and capabilities relating to regulatory filings, public disclosures, and the identification and communication of material information. Based on this evaluation, management has concluded that Freehold's disclosure controls are effective in ensuring that material information relating to the Trust is made known to management on a timely basis.

Internal control over financial reporting is a process designed to provide reasonable assurance about the reliability of financial reporting and the preparation of financial statements in accordance with GAAP. The process includes policies and procedures to maintain records that accurately and fairly reflect transactions and dispositions of assets, to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements and that receipts and expenditures are being made with proper authorization, and to provide reasonable assurance regarding prevention or timely detection of unauthorized transactions that could have a material effect on the financial statements.

Management has concluded that the design of internal controls over financial reporting is adequate.

Proposed revisions to Multilateral Instrument 52-109 are expected to be published for public comment by the end of March 2007, and new reporting requirements may apply for financial years ending on or after June 30, 2008. The proposal is expected to require the CEO and CFO to certify in their annual certificates that they have evaluated the effectiveness of internal control over financial reporting as of the end of the financial year. They will also be required to disclose in the annual MD&A a description of the process for evaluating the effectiveness of internal control over financial reporting and their conclusions about the effectiveness of internal control over financial reporting as of the end of the financial year.

In preparation for certification under the proposed instrument as at December 31, 2008, Freehold has assigned resources to evaluate the operating effectiveness of internal controls. We have also been actively engaged with our external auditors and financial advisors to develop and implement the activities necessary to meet the expected certification requirements.

Management's Report

Management has prepared the accompanying consolidated financial statements of Freehold Royalty Trust in accordance with Canadian generally accepted accounting principles.

Management is responsible for the accuracy and integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and reliable accounting records are produced for financial reporting purposes.

External auditors, KPMG LLP, were appointed by the Unitholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements of Freehold Royalty Trust. Their examination included tests and procedures considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The board of directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the audit committee, all of whose members are independent directors of Freehold Resources Ltd. The committee meets with management and the independent auditors to ensure that management's responsibilities are properly discharged.

DAVID J. SANDMEYER
President and Chief Executive Officer

JOSEPH N. HOLOWISKY
Vice President, Finance and Administration,
Chief Financial Officer and Secretary

February 28, 2007

Auditor's Report

TO THE UNITHOLDERS OF FREEHOLD ROYALTY TRUST

We have audited the consolidated balance sheets of Freehold Royalty Trust as at December 31, 2006 and 2005, and the consolidated statements of income and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KMPG LLP
Chartered Accountants
Calgary, Canada
February 28, 2007

Consolidated Balance Sheets

($000s)	December 31 2006	2005
ASSETS		
Current assets:		
Cash	$ 421	$ 192
Accounts receivable	29,850	35,728
	30,271	35,920
Reclamation fund (note 5)	2,117	1,964
Deferred long-term compensation (note 7)	86	–
Petroleum and natural gas interests (note 2)	441,754	496,194
	$ 474,228	$ 534,078
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Distributions payable to Unitholders	$ 7,376	$ 12,748
Accounts payable and accrued liabilities	13,845	6,891
	21,221	19,639
Asset retirement obligations (note 5)	4,598	4,036
Unit based compensation payable (note 7)	129	–
Long-term debt (note 4)	100,000	107,000
Future income tax liability (note 9)	3,832	3,932
Unitholders' equity:		
Unitholders' capital (note 6)	562,698	560,049
Contributed surplus (note 7)	247	–
Deficit	(218,497)	(160,578)
	344,448	399,471
	$ 474,228	$ 534,078

See accompanying notes to consolidated financial statements.

Approved on behalf of Freehold Royalty Trust by Freehold Resources Ltd. as Administrator:

WILLIAM W. SIEBENS
Director

D.NOLAN BLADES
Director

Consolidated Statements of Income and Deficit

($000s, except per unit and weighted average data)	Years Ended December 31 2006	2005
Revenue:		
Royalty income and working interest sales	$ 143,067	$ 136,914
Royalty expense (net of Alberta Royalty Credit)	(3,831)	(3,591)
	139,236	133,323
Other expenses:		
Operating	8,309	6,530
General and administrative	5,581	4,392
Interest on long-term debt	5,194	3,158
Depletion and depreciation	71,874	56,938
Accretion of asset retirement obligation (note 5)	257	252
Management fee (note 8)	2,649	2,178
	93,864	73,448
Net income before taxes	45,372	59,875
Income and capital taxes (note 9)	291	1,105
Future income tax provision (note 9)	(100)	424
	191	1,529
Net income	45,181	58,346
Deficit, beginning of year	(160,578)	(134,114)
Distributions declared	(103,100)	(84,810)
Deficit, end of year	$ (218,497)	$ (160,578)
Net income per Trust Unit, basic and diluted	$ 0.92	$ 1.36
WEIGHTED AVERAGE NUMBER OF TRUST UNITS:		
Basic	49,085,795	42,812,470
Diluted	49,093,609	42,812,470

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flow

($000s)	Years Ended December 31 2006	2005
CASH PROVIDED BY (USED IN):		
Operating:		
Net income	$ 45,181	$ 58,346
Items not involving cash:		
Depletion and depreciation	71,874	56,938
Trust Unit incentive compensation	290	–
Future income tax provision	(100)	424
Accretion of asset retirement obligation	257	252
Trust Units issued in lieu of management fee	2,649	2,178
Expenditures on reclamation	(302)	(104)
	119,849	118,034
Changes in non-cash working capital (note 10)	11,085	(20,967)
	130,934	97,067
Financing:		
Issue of Trust Units, net of issue costs	–	258,935
Long-term debt	(7,000)	80,000
Distributions paid	(108,471)	(75,848)
Changes in non-cash working capital (note 10)	(99)	(142)
	(115,570)	262,945
Investing:		
Property and royalty acquisitions (note 3)	(5,382)	(351,705)
Development expenditures	(11,446)	(7,982)
Increase in reclamation fund	(153)	(318)
Changes in non-cash working capital (note 10)	1,846	119
	(15,135)	(359,886)
Increase in cash	229	126
Cash, beginning of year	192	66
Cash, end of year	$ 421	$ 192

See accompanying notes to consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2006 and 2005.

BASIS OF PRESENTATION

Freehold Royalty Trust (the Trust) is an open-end investment trust formed under the laws of the Province of Alberta pursuant to a Trust Indenture dated September 30, 1996 as amended from time to time. The Trust holds royalty interests directly and a 99% royalty interest in the funds generated by its wholly owned subsidiary, Freehold Resources Ltd. (Freehold Resources). Freehold Resources was incorporated on June 3, 1996 and derives its income from certain petroleum and natural gas working interest properties. The Trust also holds royalty interests and working interests through Petrovera Resources (Petrovera), a general partnership acquired on May 10, 2005.

These consolidated financial statements include the accounts of the Trust, Freehold Resources and Petrovera. All inter-entity transactions have been eliminated.

1. SIGNIFICANT ACCOUNTING POLICIES

(A) PETROLEUM AND NATURAL GAS INTERESTS:

The Trust follows the full cost method of accounting.

All costs of acquiring, exploring for and developing oil and gas and related reserves are capitalized. Such costs include land acquisition, geological and geophysical, carrying charges of unproved properties, costs of drilling both productive and non-productive wells, directly related general and administrative costs and asset retirement costs. Costs are reduced by proceeds from the sale of oil and gas properties and by government grants. Gains and losses are not recognized upon disposition of oil and gas properties unless such a disposition would alter the rate of depletion by 20% or more.

(B) CEILING TEST:

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved interests and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(C) DEPLETION:

Oil and gas interests and royalty interests, including the costs of production equipment, future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. Reserves are converted to equivalent units on the basis of relative energy content.

(D) ASSET RETIREMENT OBLIGATIONS:

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

(E) INCOME AND OTHER TAXES:

The Trust is a taxable trust under the *Income Tax Act* (Canada) and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distributions to Unitholders represent an exemption from taxation equivalent to the Trust's earnings. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to its Unitholders.

Freehold Resources follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Freehold Resources can deduct royalty payments to the Trust in determining taxable income and is generally liable for income taxes on its 1% residual interest.

(F) CASH:

Cash includes cash on deposit and highly liquid investments with original maturities of three months or less.

(G) MEASUREMENT UNCERTAINTY:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

(H) UNIT BASED COMPENSATION PLANS:

A deferred trust unit plan has been established for the non-management directors of Freehold whereby fully-vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Compensation expense is recognized at the market value of the Trust Units at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital.

Effective January 1, 2006, the Trust will fund its proportionate share of the costs associated with a long-term incentive compensation plan for employees of Rife Resources, the Manager of the Trust (the Manager's LTIP). The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional rights on the date of distribution. Since participants in the Manager's LTIP receive a cash payment on a fixed vesting date, compensation expense is determined based on the intrinsic value of the rights at each period end. The valuation incorporates the period end Trust Unit price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with a corresponding increase or decrease in liabilities. The Trust has not incorporated an estimated forfeiture rate for rights that will not vest; rather, the Trust accounts for actual forfeitures as they occur.

(I) NET INCOME PER TRUST UNIT:

Basic Trust Units outstanding are the weighted average number of Trust Units outstanding for each period. Diluted Trust Units outstanding are calculated using the treasury stock method, which assumes that any proceeds received from options with a market value in excess of option price would be used to buy back Trust Units at the average market price for the period.

(J) REVENUE RECOGNITION:

Revenue from the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Trust, or the operator of the Trust's royalty properties, to its customers.

2. PETROLEUM AND NATURAL GAS INTERESTS

($000s)	**2006**	2005
Petroleum and natural gas interests	**$ 751,485**	$ 734,051
Accumulated depletion and depreciation	**(309,731)**	(237,857)
Petroleum and natural gas interests, net	**$ 441,754**	$ 496,194

The depletion calculation included $2.9 million (2005 - $2.6 million) for estimated future development costs associated with proved undeveloped reserves and excluded $19.4 million (2005 – $14.1 million) for the lower of cost and market value of unproved lands.

The Trust's ceiling test calculation, performed at December 31, 2006, resulted in no impairment loss. The future prices used by the Trust in estimating cash flows were based on forecasts by an independent qualified reserves evaluator, adjusted for the Trust's quality, transportation, and contract differences. The following table summarizes the benchmark prices used in the calculation.

Year	WTI Crude Oil *(US$/bbl)*	Foreign Exchange Rate	Edmonton Par Crude Oil *(Cdn$/bbl)*	AECO Natural Gas *(Cdn$/MMBtu)*
2007	65.73	0.87	74.10	7.72
2008	68.82	0.87	77.62	8.59
2009	62.42	0.87	70.25	7.74
2010	58.37	0.87	65.56	7.55
2011	55.20	0.87	61.90	7.72
Average annual increase, thereafter	2%	–	2%	2%

3. BUSINESS COMBINATION

On May 10, 2005, the Trust closed the acquisition of Petrovera Resources, a general partnership that owns certain royalty, mineral title and working interests. The acquisition cost of $351.7 million (net of adjustments) was funded partially with a concurrent equity financing consisting of 13.5 million Trust Units at $15.55 per Trust Unit and a private placement to the vendor of 3.9 million Trust Units at $15.55 per Trust Unit for net proceeds of $258.9 million. The remaining cost of $92.8 million was financed utilizing the Trust's credit facilities. The acquisition was accounted for using the purchase method of accounting with the results of operations being included from May 10, 2005.

The fair values of the acquisition costs were allocated as follows:

($000s)	
Petroleum and natural gas interests	$ 351,705
Asset retirement obligations	(19)

4. LONG-TERM DEBT

The Trust has a $150 million revolving-term credit facility, extendible annually, on which $100 million was drawn at December 31, 2006. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period. In addition, Freehold has available a $15 million extendible revolving operating facility, undrawn at December 31, 2006. The facilities are up for renewal in May 2007.

Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance, or LIBOR rates, plus applicable margins ranging from 85 to 140 basis points, and standby fees.

The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets.

5. ASSET RETIREMENT OBLIGATIONS

The Trust has no asset retirement obligations on its royalty interest properties. The Trust's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of the Trust's total asset retirement obligation is estimated to be $4.6 million (discounted at a weighted average credit adjusted risk free rate of 6.1%), with the undiscounted value being $12.2 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away.

	December 31	
($000s)	**2006**	2005
Balance, beginning of year	**$ 4,036**	$ 3,937
Liabilities incurred	**364**	210
Liabilities added upon acquisition	**–**	19
Liabilities settled	**(302)**	(104)
Liabilities disposed	**–**	(352)
Revision in estimates [1]	**243**	74
Accretion expense	**257**	252
Balance, end of year	**$ 4,598**	$ 4,036

1 Revision in estimates is mainly a result of changes in estimates provided by the Trust's independent qualified reserves evaluator.

A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. All liabilities settled during the periods are paid from the reclamation fund.

6. UNITHOLDERS' CAPITAL

The Trust has authorized an unlimited number of Trust Units of which 49,174,197 were issued and outstanding at December 31, 2006 (2005 – 49,031,581).

TRUST UNITS ISSUED AND OUTSTANDING

	2006			2005		
	Number		Amount ($000s)	Number		Amount ($000s)
Balance, beginning of year	49,031,581	$	560,049	31,544,236	$	298,936
Issued for cash	–		–	17,363,520		270,003
Less: Issue costs	–		–	–		(11,068)
Issued in lieu of management fee	142,616		2,649	123,825		2,178
Balance, end of year	49,174,197	$	562,698	49,031,581	$	560,049

The Trust has reserved 800,000 Trust Units pursuant to its Management Agreement with the Manager, of which 30,677 have been issued to date.

7. UNIT BASED COMPENSATION

(A) DEFERRED TRUST UNIT PLAN

In May 2006, the Unitholders approved a deferred trust unit plan for non-management directors with effect from January 1, 2006. The plan consists of fully vested deferred trust units which are granted annually. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at December 31, 2006 there were 12,559 deferred trust units outstanding which are redeemable for an equal number of Trust Units any time after the director's retirement.

DEFERRED TRUST UNITS

	December 31, 2006
Balance, beginning of period	–
Annual grant	11,165
Additional units resulting from distributions	1,394
Balance, end of period	12,559

For the year ended December 31, 2006, the Trust expensed $247,000 as unit based compensation, with a corresponding increase to contributed surplus.

CONTRIBUTED SURPLUS

($000s)		December 31, 2006
Balance, beginning of period	$	–
Trust Unit incentive compensation expense		247
Balance, end of period	$	247

(B) MANAGER'S LTIP

In May 2006, the Board of Directors agreed to fund the Trust's proportionate share of a long-term incentive compensation plan for all employees of the Manager (the Manager's LTIP), with effect from January 1, 2006. The Manager's LTIP will result in employees receiving cash compensation in relation to the value of a specified number of notional units. The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions made by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the Trust Unit price. In addition, there is a performance multiplier based in part on the Trust's performance over the vesting period, which may range from 0.25 to 1.5 times the market value.

At December 31, 2006, the Trust had accrued $129,000 as a long-term liability relating to incentive compensation pursuant to the Manager's LTIP and expensed $43,000 for the year then ended.

8. RELATED PARTY TRANSACTIONS

The Manager provides certain services for a fee based on a specified number of Trust Units per quarter, pursuant to a management agreement which has a term of three years and will be renewed on November 26, 2007 unless terminated. During 2006, the management fee charged was 142,616 Trust Units with an ascribed value of $2.6 million (2005 – 123,825 Trust Units with an ascribed value of $2.2 million).

During the year, the Manager charged the Trust $3.7 million (2005 – $3.0 million) in general and administrative costs. At December 31, 2006, there was $770,000 (2005 – $219,000) included in accounts payable relating to these costs.

Prior to 2006, the Manager earned a fee of 1.5% of the purchase price of oil and gas properties acquired by the Trust. During 2005, the Manager acquired $353.7 million (gross purchase price) of properties on behalf of the Trust and was paid $5.3 million. This fee was charged to petroleum and natural gas interests as part of the properties acquired. There were no fees charged in 2006 as the Manager amended the management agreement to remove the 1.5% acquisition fee.

9. INCOME TAXES

Freehold Resources uses the asset and liability method of accounting for income taxes, as described in note 1. The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Trust's earnings before income taxes. This difference results from the following items:

($000s)	**2006**	2005
Earnings before income taxes and capital taxes	**$ 45,372**	$ 59,875
Combined federal and provincial tax rate	**35.2%**	38.0%
Computed expected income tax expense	**$ 15,978**	$ 22,723
Increase (decrease) in income tax resulting from:		
Non-taxable earnings of the Trust	**(15,337)**	(21,009)
Non-deductible Crown charges	**179**	254
Resource allowance	**(256)**	(505)
Benefit of future rate reductions	**(63)**	(56)
Changes in enacted tax rates	**(566)**	2
Capital taxes	**253**	120
Other	**3**	–
Total income and capital taxes	**$ 191**	$ 1,529

Total income taxes are comprised of:

($000s)	2006	2005
Current income and capital taxes	$ 291	$ 1,105
Future taxes (reduction)	(100)	424
Total income and capital taxes	$ 191	$ 1,529

The components of Freehold Resources' future income taxes at December 31 are as follows:

($000s)	2006	2005
Future income tax liabilities:		
Petroleum and natural gas interests	$ 5,295	$ 5,288
Future income tax assets:		
Asset retirement obligations	(1,463)	(1,356)
Net future income tax liability	$ 3,832	$ 3,932

On a consolidated basis, the Trust's carrying value for book purposes exceeds the amount available for tax purposes by $278 million.

In 2006, the taxation authorities released for comment draft legislation which would result in a tax structure for trusts similar to that of corporations. If the proposed legislation is implemented, the Trust will be required to recognize, in the period in which the change is substantially enacted, future income taxes on temporary differences in the Trust.

10. SUPPLEMENTAL CASH FLOW DISCLOSURE

CHANGES IN NON-CASH WORKING CAPITAL BALANCE

($000s)	2006	2005
Accounts receivable	$ 5,878	$ (22,931)
Accounts payable and accrued liabilities	6,954	1,941
	$ 12,832	$ (20,990)

CASH EXPENSES PAID

($000s)	2006	2005
Interest	$ 5,294	$ 3,301
Taxes	1,251	1,465

11. FINANCIAL INSTRUMENTS

The fair values of the Trust's accounts receivable and accounts payable and accrued liabilities approximate their carrying values due to their short terms to maturity.

The Trust is exposed to foreign currency fluctuations as crude oil prices received are referenced in U.S. dollar denominated prices.

The Trust pays interest on its long term debt at prevailing market rates.

A large part of the Trust's accounts receivable are with oil and gas industry operators, either as joint venture partners or as payors of various royalty agreements. The Trust markets approximately 65% of its production along with the operator or royalty payor under the terms of a diverse number of agreements. When it can, the Trust takes its production in kind (currently 35%) and sells to two primary purchasers under normal industry sale and payment terms. None of Freehold's production is hedged.

Supplementary Information

LAND HOLDINGS BY PROVINCE

(gross acres)[1]	**2006**	2005	2004
Alberta	**1,218,097**	1,207,929	699,556
Saskatchewan	**464,977**	463,948	339,303
Ontario	**296,109**	244,447	0
British Columbia	**81,904**	81,559	25,946
Manitoba	**8,283**	8,062	2,224
Total	**2,069,370**	2,005,945	1,067,029
Undeveloped land	**598,235**	555,171	291,729

1 Gross acres represents the total number of acres in which we have an interest.

LAND SUMMARY

(gross acres)[1]	**2006**		2005		2004	
	Gross Acres	**Undeveloped Acres**	Gross Acres	Undeveloped Acres	Gross Acres	Undeveloped Acres
Mineral title lands[2]	**550,636**	**164,199**	548,360	157,966	489,978	151,142
Gross overriding royalty lands[3]	**1,218,700**	**365,381**	1,164,262	330,190	280,775	77,339
Royalty assumption lands[4]	**96,082**	**19,620**	96,082	17,137	96,402	17,696
Royalty lands	**1,865,418**	**549,200**	1,808,704	505,293	867,155	246,177
Working interest properties	**203,952**	**49,035**	197,241	49,878	199,874	45,552
Total land holdings	**2,069,370**	**598,235**	2,005,945	555,171	1,067,029	291,729

1 Gross acres represents the total number of acres in which we have an interest.
2 The royalties received from the sale of oil, natural gas and potash produced from the leased mineral title lands are determined by the individual lease agreements. Mineral title lands are held in perpetuity.
3 Gross overriding royalty lands consist of properties owned by a number of third party oil and gas companies in respect of which varying royalties or net profits interests have been reserved to Freehold.
4 Mineral title properties owned by a number of third party oil and gas companies in respect of which gross overriding royalties varying from 4.7% to 6.5% have been reserved to Freehold.

ROYALTY INTEREST DRILLING SUMMARY

	2006		2005		2004	
	Gross	**Equivalent Net[1]**	Gross	Equivalent Net[1]	Gross	Equivalent Net[1]
Oil	**204**	**6.7**	209	8.3	146	4.5
Natural gas	**488**	**5.9**	554	10.1	459	5.5
Other	**80**	**5.7**	111	6.2	61	2
D&A	**6**	**0.4**	10	0.4	5	0.3
Total	**778**	**18.7**	884	25	671	12.3
Net success rate		**99%**		99%		99%

1 Equivalent net wells are the aggregate of the numbers obtained by multiplying each gross well by our royalty interest percentage.

WORKING INTEREST DRILLING SUMMARY

	2006		2005		2004	
	Gross	**Net**	Gross	Net	Gross	Net
Oil	**36**	**6.3**	44	6.9	32	3.6
Natural gas	**32**	**0.9**	69	1.8	57	1.8
Other	**5**	**0.3**	4	0.4	1	0
Total	**73**	**7.5**	117	9.1	90	5.4
Net success rate		**100%**		100%		99%

NET OIL AND GAS RESERVES [1, 2]

	Developed Producing	Proved Developed Non-producing	Undeveloped	Total Proved	**Proved Plus Probable**
Light and medium oil *(Mbbls)*	4,373	19	0	4,393	**6,206**
Heavy oil *(Mbbls)*	6,213	0	231	6,445	**10,038**
Natural gas *(MMcf)*	41,015	97	10	41,121	**62,019**
NGL *(Mbbls)*	1,029	2	0	1,031	**1,431**
Total *(Mboe)*	18,452	37	233	18,722	**28,012**
Reserve life index *(years)* [3]	7.2	—	—	7.2	**9.6**

1 Columns may not add due to rounding.
2 Evaluated by Trimble Engineering Associates Ltd. effective December 31, 2006.
3 Calculated by dividing Trimble Engineering Associates Ltd.'s forecast of 2007 net production into the remaining net reserves.

RECONCILIATION OF NET OIL AND GAS RESERVES [1]

	Proved (Mboe)	Probable (Mboe)	**Proved Plus Probable** (Mboe)	Net Present Value [2] ($000s)
December 31, 2005	20,412	10,118	**30,530**	742,832
Production [3]	(3,017)	(58)	**(3,074)**	(69,912)
Development additions	651	496	**1,146**	37,163
Acquisitions [4]	256	119	**376**	5,123
Revisions:				
Operating costs	—	—	—	(7,259)
Pricing	—	—	—	(24,503)
Royalties	—	—	—	(3,341)
Future capital, ARC	—	—	—	(5,285)
Reserves	420	(1,385)	**(966)**	(38,551)
December 31, 2006	**18,722**	**9,290**	**28,012**	**636,267**
Change over prior year	(1,690)	(828)	**(2,518)**	(106,565)

1 Columns may not add due to rounding.
2 Net present value of proved plus probable reserves based on forecast prices and costs, discounted at 10% before tax. Based on the December 31, 2006 escalated oil and gas price forecasts by an independent qualified reserves evaluator.
3 Estimated by Trimble Engineering Associates Ltd.
4 Wildmere Unit interest acquired July 1, 2006.

NET PRESENT VALUE [1, 2]

	Discounted at			
($000s)	0%	5%	**10%**	15%
Proved				
Developed producing	891,975	606,519	**474,823**	397,854
Developed non-producing	1,561	1,452	**1,361**	1,282
Undeveloped	4,572	3,519	**2,763**	2,209
Total proved	898,108	611,490	**478,947**	401,346
Probable	490,865	243,780	**157,320**	115,839
Proved plus probable	**1,388,973**	**855,270**	**636,267**	**517,185**

1 Columns may not add due to rounding.
2 Forecast prices and costs, before tax. Based on the December 31, 2006 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

NET PRESENT VALUE OF RESERVES BY PRODUCT TYPE [1]

($000s)	Total Proved	**Proved Plus Probable**
Light and medium oil	140,186	**178,019**
Heavy oil	160,200	**217,871**
Natural gas	178,561	**240,377**

1 Forecast prices and costs, before tax, discounted at 10%. Based on the December 31, 2006 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

FORECAST PRICES USED IN ESTIMATES [1]

Year	Oil: WTI Cushing Oklahoma (US$/bbl)	Oil: Edmonton Par Price 40° API (Cdn$/bbl)	Oil: Bow River Hardisty 24.9° API (Cdn$/bbl)	Natural Gas: AECO 30 Day Spot (Cdn$/MMBtu)	Natural Gas Liquids: Propane (Cdn$/bbl)	Natural Gas Liquids: FOB Field Gate Butane (Cdn$/bbl)	Natural Gas Liquids: Pentane (Cdn$/bbl)	Inflation Rate (%/year)	Exchange Rate (US$/Cdn$)
2007	65.73	74.10	53.35	7.72	43.94	55.23	75.88	5.0	0.87
2008	68.82	77.62	55.89	8.59	46.03	57.85	79.49	4.0	0.87
2009	62.42	70.25	50.58	7.74	41.66	52.36	71.94	3.0	0.87
2010	58.37	65.56	47.20	7.55	38.88	48.87	67.14	2.0	0.87
2011	55.20	61.90	44.57	7.72	36.71	46.14	63.40	2.0	0.87
Thereafter, per year	2%	+2%	+2%	+2%	+2%	+2%	+2%	2.0	0.87

1 AS AT DECEMBER 31, 2006.

RESERVE LIFE INDEX (RLI) [1]

	Proved Producing	Total Proved	**Proved Plus Probable**
Net reserves *(Mboe)* [2]	18,451.6	18,721.7	**28,011.8**
Net production *(Mboe)* [2]	2,562.2	2,601.7	**2,926.7**
RLI *(years)*	7.2	7.2	**9.6**

1 Calculated by dividing the evaluator's forecast of 2007 net interest production into the remaining net interest reserves.
2 Net reserves and production include the principal products (light and medium crude oil, heavy oil and natural gas) and associated gas and natural gas liquids.

RESERVE LIFE INDEX (RLI) BY PRINCIPAL PRODUCT [1]

	Proved Producing	Total Proved	**Proved Plus Probable**
Light and medium oil			
Net reserves *(Mbbl)*	4,303	4,323	**6,109**
Net production *(Mbbl)*	442	454	**533**
RLI *(years)*	9.7	9.5	**11.5**
Heavy oil			
Net reserves *(Mbbl)*	6,213	6,445	**10,038**
Net production *(Mbbl)*	1,018	1,043	**1,138**
RLI *(years)*	6.1	6.2	**8.8**
Natural gas			
Net reserves *(MMcf)*	35,248	35,345	**54,021**
Net production *(MMcf)*	5,161	5,171	**5,935**
RLI *(years)*	6.8	6.8	**9.1**

1 Based on principal product type within production group and excludes associated gas and natural gas liquids.

ANALYSIS OF DEVELOPMENT AND ACQUISITION COSTS

	Three-Year Results	**2006**	2005	2004
Development expenditures *($000s)*	25,251	**11,446**	7,982	5,823
Change in future development capital estimates *($000s)*	(4,907)	**(2,549)**	235	(2,593)
Net reserve additions by development *(Mboe)*	2,908	**1,146**	945	817
Development costs *($/boe)* [1]	7.00	**7.76**	8.70	3.95
Acquisition expenditures *($000s)*	369,968	**5,382**	351,705	12,881
Net reserve additions by acquisition *(Mboe)*	13,699	**376**	12,889	434
Acquisition costs *($/boe)*	27.01	**14.33**	27.29	29.68
Total expenditures *($000s)*	395,219	**16,828**	359,687	18,704
Change in future development capital estimates *($000s)*	(4,907)	**(2,549)**	235	(2,593)
Net reserve additions *(Mboe)*	16,607	**1,522**	13,834	1,251
Development and acquisition costs *($/boe)*	23.50	**9.38**	26.02	12.88

1 Development expenditures plus change in future capital, divided by reserves added.

RECYCLE STATISTICS

($ per boe, except as noted)	Three-Year Results	**2006**	2005	2004
Operating netback [1, 4]	41.43	**42.64**	45.49	34.05
Development and acquisition costs [2, 4]	23.50	**9.38**	26.02	12.88
Recycle ratio *(times)* [3]	1.8	**4.5**	1.7	2.6

1 Total revenue, less operating costs and royalty expenses net of Alberta Royalty Credit.
2 Development expenditures, plus change in future capital, plus acquisition costs, divided by net reserves added through development and acquisition activities.
3 Operating netback divided by the average cost of acquiring and developing new reserves.
4 Operating netback is based on gross production, while development and acquisition costs are based on net reserves.

Ten-Year Historical Review

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Financial *($000s, except as noted)*										
Gross revenue	**143,067**	136,914	78,491	73,166	63,143	61,885	64,500	36,355	24,839	39,953
Funds generated from operations	**119,849**	118,034	64,313	60,658	51,489	49,728	51,882	27,304	15,210	30,797
Per Trust Unit *($)*	**2.44**	2.76	2.04	1.95	1.71	1.72	1.94	1.03	0.57	1.16
Net income [1]	**45,181**	58,346	36,892	37,078	27,529	27,304	31,758	8,714	(9,278)	3,045
Per Trust Unit *($)*	**0.92**	1.36	1.17	1.19	0.91	0.95	1.19	0.33	(0.35)	0.12
Distributions declared	**103,100**	84,810	54,490	53,149	39,530	45,264	35,226	20,757	17,186	29,081
Per Trust Unit *($)*	**2.10**	1.92	1.73	1.70	1.31	1.56	1.32	0.78	0.65	1.10
Development expenditures	**11,446**	7,982	5,823	5,894	2,946	2,992	5,161	940	1,790	2,613
Acquisitions	**5,382**	351,705	13,061	3,386	2,326	29,707	5,326	–	–	27,407
Long-term debt	**100,000**	107,000	27,000	18,000	30,000	33,000	38,000	39,288	39,288	38,175
Unitholders' equity	**344,448**	399,471	164,822	180,992	185,326	196,317	182,898	185,742	197,346	233,261
Operating										
Production										
Oil *(bbls/d)*	**4,865**	4,488	3,594	3,688	3,926	3,873	3,353	2,921	3,208	3,566
NGL *(bbls/d)*	**358**	345	283	317	288	354	327	302	339	347
Natural gas *(MMcf/d)*	**19.1**	16.8	10.3	10.9	10.7	11.2	11.0	11.2	11.9	15.5
Oil equivalent *(boe/d)*	**8,412**	7,636	5,588	5,817	6,004	6,086	5,523	5,082	5,531	6,493
Average sales price										
Oil *($/bbl)*	**50.24**	46.65	38.08	32.77	31.25	24.42	32.98	21.82	12.91	19.22
NGL *($/bbl)*	**50.29**	50.58	37.29	30.95	25.09	29.91	32.81	16.94	13.82	19.02
Natural gas *($/Mcf)*	**6.54**	8.55	6.28	6.18	3.81	5.64	4.71	2.48	1.91	1.79
Oil equivalent *($/boe)*	**46.07**	48.53	37.91	34.01	28.44	27.63	31.39	18.99	12.45	15.84
Operating netback *($/boe)*	**42.64**	45.49	34.05	30.51	25.43	24.30	28.26	17.10	9.94	14.63
Land *(gross acres) (000s)*	**2,069**	2,006	1,067	1,011	1,001	1,005	872	869	869	836
Undeveloped land *(gross acres) (000s)*	**598**	555	292	242	235	237	141	136	133	78
Reserves *(Mboe)* [2]	**28,012**	30,530	21,163	22,052	26,813	28,177	28,150	29,062	29,952	30,809
Reserve life index *(years)*	**9.6**	9.9	10.6	11.0	12.2	12.7	14.0	15.7	14.8	13.0
Trust Units										
High *($)*	**23.06**	19.30	18.42	17.19	11.35	10.10	9.50	6.90	9.80	11.85
Low *($)*	**12.43**	14.25	14.02	10.50	9.00	8.00	5.60	4.13	4.15	8.40
Close *($)*	**14.81**	18.81	17.45	16.35	10.88	9.20	8.70	5.95	4.43	9.10
Volume *(000s)*	**35,512**	28,320	11,567	10,970	7,323	8,162	6,752	5,782	9,686	11,392
Outstanding *(millions)*										
At period end	**49.2**	49.0	31.5	31.5	30.2	30.1	26.7	26.6	26.6	26.5
Weighted average	**49.1**	42.8	31.5	31.2	30.2	28.8	26.7	26.6	26.5	26.4

1 2003 and prior years were restated in 2004 for the adoption of new Canadian standards for asset retirement obligations.

2 The reserves data for 2003-2006 is not directly comparable to data for the years 1996 through 2002 due to new reserve definitions and evaluation methodology that came into effect in 2003. Reserves for 2003-2006 were evaluated under National Instrument 51-101 and are reported as net proved plus probable reserves. Previously, reserves were evaluated under National Policy 2-B and reported as gross (before royalties) proved plus half probable (established) reserves.

UNITHOLDER INFORMATION

DISTRIBUTION POLICY AND DATES

We make regular monthly distributions, the amounts of which are determined by the board of directors and subject to change depending upon the business environment and in particular fluctuations in commodity prices. Record dates are the end of each month, and payment dates are the fifteenth day of the following month.

2007 REPORTING CALENDAR

Feb. 28: Fourth quarter and 2006 year-end results
May 9: First quarter results
Aug. 9: Second quarter results
Nov. 7: Third quarter results

UNITHOLDER PLANS

DIRECT DEPOSIT PLAN

A Direct Deposit Plan is in place to provide Unitholders who have Canadian bank accounts with a method of receiving cash distributions as a direct deposit into their bank accounts.

DISTRIBUTION REINVESTMENT PLAN (DRIP)

A DRIP is in place to provide Unitholders who are residents of Canada with a method of reinvesting cash distributions into new Trust Units.

U.S. CURRENCY PAYMENT PLAN

Unitholders may elect to receive their distribution payments in U.S. funds.

ANNUAL MEETING OF UNITHOLDERS

The Annual Meeting of Unitholders will be held on Wednesday, May 9, 2007, at 3:30 p.m. in the Lecture Theatre, Sunlife Plaza Conference Centre, Plus 15 (2nd level), 140 – 4 Avenue S.W., Calgary, Alberta.

TRUSTEE AND TRANSFER AGENT

For information about distribution cheques, Trust Unit certificates, transfers, duplicate mailings and address changes, please contact:

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Corporate Trust Department
710, 530 – 8 Avenue S.W.
Calgary, Alberta T2P 3S8

or

Computershare Trust Company of Canada
100 University Avenue, 9th Floor
Toronto, Ontario M5J 2Y1
Telephone: 1-800-564-6253
Fax: 1-888-453-0330

Website: www.computershare.com
Email: service@computershare.com

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www.freeholdtrust.com

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Symbol: **FRU.UN**

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Computershare Trust Company of Canada
Calgary, Alberta and Toronto, Ontario

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Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
Calgary, Alberta

Royal Bank of Canada
Calgary, Alberta

EVALUATION ENGINEERS

Trimble Engineering Associates Ltd.
Calgary, Alberta

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